CANADA

BACKGROUND PAPER

ON

NEGATIVE SALVAGE VALUE

Prepared by: National Energy Board Staff

September 1985

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Summary and Conclusions

1. Summary and Conclusions

Eventually, all pipelines in Canada will reach the end of their useful life. At that time the acceptable manner of abandoning the pipeline facilities may be to remove them. Given the nature of pipeline facilities, it is reasonable to assume that, in most cases, the cost of removal will exceed the salvage revenue generated from the sale of the removed material for scrap or use by others. This paper addresses the problems associated with the net negative salvage costs which will be incurred if removal costs exceed the salvage revenues.

The concept of net negative salvage value was perhaps first raised as an issue by the utilities operating nuclear power stations. Recently, pipeline companies have been arguing that this issue also applies to their industry.

The pipeline companies under the Board's jurisdiction are required to comply with the NEB Pipeline Regulations. On the subject of pipeline abandonment these regulations currently require a company to remove abandoned pipelines unless the Board approves an alternative course of action.

Some segments of a pipeline company's facilities may be abandoned prior to the end of the complete system's operating life. In this instance, revenues can probably be raised through the company's tolls to pay any net negative salvage associated with such abandonments. However, when an entire pipeline's useful economic life is exhausted and it is incapable of generating further operating revenues, the opportunity for adjusting the tolls to pay for the abandonment will have lapsed. It is probably with this concern in mind that companies are now seeking adjustments in their tolls to provide for the collection of negative salvage funds prior to the exhaustion of the useful economic life of the pipelines. This approach presumes that net negative salvage costs are just as appropriately elements of cost of service as installation costs. It also presumes that the criteria with which to decide how best to abandon pipelines and the future cost of such abandonments can be roughly predetermined.

There are three basic pipeline abandonment options available. These are: removal, abandonment in place with continuing maintenance, and outright abandonment in place. The main problem associated with the latter option is that it can be expected that an abandoned pipeline that is not maintained will eventually collapse due to the effects of corrosion. The surface soil depression that subsequently develops may become a safety hazard and present a host of environmental and land use problems. The magnitude of these problems is a function of site specific considerations such as pipe diameter and soil and terrain characteristics. The option of maintaining abandoned pipelines cannot eliminate the pipe collapse problem entirely, but it can be expected to significantly retard the corrosion process. The effect of utilizing heavy equipment on the right of way to remove pipelines can also introduce environmental and land use concerns. However, certain easement agreements may require the removal of facilities upon abandonment.

This background paper examines each of the available options as a function of pipe diameter and local soil and terrain conditions. Not surprisingly, the analysis leads to the general conclusion that the best course of action is to either remove or maintain large and medium diameter abandoned pipelines, while small diameter pipelines could be abandoned in place.

Other abandonment options that are discussed include the controlled pipe collapse and solid fill techniques. Neither of these have been demonstrated to be technologically feasible on a large scale. Another possibility is to permit the companies to return the right-of-way and pipelines to the landowners. Presumably this would include a negotiated settlement to permit the landowners to implement appropriate measures to ensure that long-term safety standards would be respected and to accept responsibility for the line.

Both abandonment in place with maintenance and abandonment by removal can involve substantial costs. Cost estimates submitted by the companies to date cover a wide range, but some convergence, for unit net negative salvage costs, in the $30,000 to

$40,000/km range, has been observed. These estimates have tended not to include provision for the outright abandonment or abandonment with maintenance options. Another potential concern is that the difference between the cost estimates to remove pipelines and to install them seems greater than one might expect.

To illustrate the effect that negative salvage could have on tolls, an assessment of the cost of negative salvage (in the first year) versus the total current cost of service was approximated. Under the assumption that some sections of a pipeline would not have to be removed, this demonstrated that the first year negative salvage costs (calculated on a straight line basis) could amount to a very small part of the current cost of service for the companies examined (i.e. for TCPL, less than one percent of cost of service).

Financially there are many regulatory precedents which govern the collection of removal or maintenance costs, well in advance of the work being performed. While delaying the collection of negative salvage funds appears to remain a viable option, escalation of the annual negative salvage funds required in the future must be taken into account. Alternatives to the straight line method of recovering negative salvage costs would provide a degree of tariff levelling that may be desirable.

The paper explores five methods of providing for negative salvage costs. The external trust, in general, is most favoured as it provides the greatest level of assurance that the funds will be available. The risk of an over or under collection of funds should be mitigated to an acceptable level by allowing for the periodic recalculation of a pipeline's negative salvage value. The problems arising from income tax legislation that are examined in the paper may ultimately be overcome depending on the Government's rulings on applications for changes.

In general the issues which negative salvage value raises are:

(i) whether to allow for the (approximate) predetermination of which pipeline facilities will have to be removed or abandoned with maintenance.

If so, then

(ii) whether to accept the premise that the net salvage value in these instances will prove to be negative.

If so, then

(iii) whether to accept in principle, where negative salvage costs are anticipated, that they be provided for in the revenues of the companies prior to abandonment.

If so, then

(iv) whether to commence providing for negative salvage costs at this time or in this decade (or to defer indefinitely the collection of funds to cover negative salvage costs).

If now, then

(v) what amount of negative salvage costs should be provided for (in individual cases).

And

(vi) what collection method should be provided in a company's tolls including: the time of start up, the time distribution of cost recovery, and the management scheme for the funds collected.

These decisions require an appreciation of both the minimum standards of safety that will be acceptable in future and the financial impact that the prepayment of funds would impose on the current users of the pipelines.

In conclusion, as long as the Pipeline Regulations require the companies to remove their facilities after abandonment, "unless otherwise approved by the Board", then the companies can be expected to continue to seek the Board's view on what will need to be removed so that funds can be set aside. Today, it is evident that it will be necessary to remove many facilities but the annual cost to be set aside is generally still small, relative to cost of service.

Chapter 2
Background

2.1 Introduction

The accounting profession generally accepts that depreciation should reflect the systematic allocation, over the useful life of an asset, of its capital costs net of any (positive or negative) salvage. However, regulatory authorities have generally been slow to recognize the negative salvage costs associated with the removal of a utility's assets in the calculation of depreciation rates, probably as a result of some or all of the following reasons:

(i) estimates of negative salvage amounts involve substantial uncertainty,

(ii) the allowance in a company's tolls of an amount for negative salvage would involve revenues being collected before costs were incurred,

(iii) negative salvage costs are not perceived as being necessary for a generation or more, hence little or no urgency is associated with the problem, and

(iv) there is concern that the negative salvage fund, to be financed by the tollpayers, must be reliably managed.

Gradual acceptance by regulatory agencies of negative salvage costs is now being achieved. Largely this can be attributed to the efforts of the American utilities operating nuclear power plants. Consideration of how to dispose of some of the nuclear plants that have now exhausted their useful life has demonstrated technical problems, costs, and public pressure which may be largely unique to that industry. Nevertheless, some regulatory agencies have recognized the negative salvage costs sought by certain pipeline companies under their jurisdictions. In achieving this recognition, regulated utilities have put forward several arguments addressing the problems listed above. Among these arguments are the following:

(i) the uncertainty associated with negative salvage amounts is not inconsistent with the uncertainty associated with estimating the other elements of depreciation, namely: the useful life and positive salvage,

(ii) the cost for negative salvage is accepted by the utility when the facility is constructed even though the funds are not spent until the useful life is exhausted,

(iii) substantial negative salvage costs are incurred throughout both the useful life of a pipeline and during the period when the pipeline's (or any of its components') activities are being 'wound up'. Currently such incurred negative salvage costs are charged against depreciation even though depreciation revenue does not provide for these costs, and

(iv) solutions related to how to manage negative salvage funds which are acceptable to the public, the users, and the utilities are being found and range from 'no-cost capital' for the utility to external low-risk annuity funds.

A number of pipeline companies under the Board's jurisdiction have expressed interest in pursuing the subject of negative salvage. This has culminated in addressing, in principle, arguments for negative salvage at the 1984 Westcoast toll methodology hearing.

The foregoing described the background and environment against which the Board must address the issue of negative salvage costs. The purpose of the balance of the paper is to look at the precedents related to negative salvage, their application to the Board, and to examine the physical and financial aspects of the subject in detail.

2.2 American Precedents

Of the 19 cases which were reviewed, five concerned gas pipelines and 14 dealt with nuclear power generating facilities. The decisions reviewed support the concept of recovering negative salvage costs from the current customers who benefit from use of the assets. In some cases it was held that the magnitude of the decommissioning allowance should increase over time so that inflation will not reduce the burden on future customers at the expense of existing customers (for example, a graduated charge, based upon a five percent inflation rate, was used). Since

negative salvage values and decommissioning charges are usually based on estimates, periodic reviews and revisions have been advocated. Generally, the following criteria have been considered in the decisions:

(1) assurance of availability of funds;

(2) cost to ratepayers;

(3) flexibility to adapt to changing costs;

(4) equity to ratepayers.

Although the majority of these cases relate to the decommissioning costs of nuclear power plants, the principles should be applicable to pipelines as well. The question of funding is particularly interesting. The amounts collected from customers could be accumulated in various funds. Funding methods mentioned were:

(A) An *internal funded reserve* which restricts usage of the funds;

(B) An *external funded reserve* through the use of a trust or other fund; and

(C) An *internal unfunded reserve* which allows the Company to use the funds for general corporate purposes.

(D) *Prepayment* at the time of initial plant operation based on estimated future costs.

Method (D) might not be generally considered for pipelines, but was discussed especially in cases of the relatively more risky nuclear power plants.

Several other funding methods are possible. Frequently, the safer funding methods, e.g. an external one, tend to be more costly. Cost differentials between funding methods, however, may be rather small when viewed in the context of consumers' total utility bills.

A more detailed examination of the American precedents is included in Appendix I.

2.3 Canadian Precedents

The Ontario Hydro and New Brunswick Electric Power Commission (NBEPC) precedents concern nuclear power plants; however, they are relevant to our discussion. They are Canadian precedents involving large liabilities[1] for estimated future costs of disposing of irradiated nuclear fuel and decommissioning nuclear generating stations. The external auditors of both utilities reported that their financial statements present fairly their financial position, etc. This indicates the auditors' acceptance of the "nuclear unit decommissioning" concept and the way the utilities have provided for it.

Ontario Hydro, in its *1983 Annual Report*, showed an item called "accrued irradiated fuel disposal and fixed asset removal costs" under "other liabilities". Studies have been carried out to estimate the costs of decommissioning Ontario Hydro's nuclear generating stations after the end of their service lives. Certain assumptions used in estimating decommissioning costs have also been stated in the above-mentioned report, and when discussing depreciation, Ontario Hydro added:

> "Net removal costs amortized to operations include the estimated costs of decommissioning nuclear stations and, commencing in 1983, the estimated costs of removing certain nuclear reactor fuel channels. Estimates of net removal costs, interest rates, and the amortization periods are subject to periodic review. Changes in estimated costs are implemented on a remaining service life basis from the year the changes can be first reflected in electricity rates."

NBEPC presented evidence in a hearing before the NEB in Fredericton, N.B. (24 Nov. to 2 Dec. 1981), concerning its application for orders and licences to export power to the U.S. Decommissioning costs of the Lepreau power station are briefly mentioned in the NEB Reasons for Decision of March 1982. NBEPC stated its intention to charge all its customers, including export customers, an amount necessary to cover decommissioning costs; however, the Decision does not specifically address this issue. The respective amount in the export price was proposed to be the same as the charge to Canadian customers, and the Canadian rates are not under the jurisdiction of the NEB. The small charge levied in respect of eventual Lepreau station decommissioning was expected to be 0.04 cents/KWh, and the charge in respect of long-term waste management was estimated at 0.10 cents/KWh. However, from recent billings it appears that these charges are now slightly different.

In its *Annual Report 1982/83*, NBEPC said:

> "The Commission, to be assured of having adequate funds available in the future, has adopted a policy of charging income annually, with amounts considered adequate along with investment income to cover the cost for the permanent disposal of irradiated nuclear fuel and decom-

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1 Ontario Hydro at 31 December 1983:

Accrued irradiated fuel disposal costs	$110,229,000
Accrued fixed asset removal costs	37,419,000
Total	**$147,648,000**

NBEPC at 31 March 1984:

Irradiated fuel management and nuclear unit decommissioning	$ 79,460,930

missioning the station to return the site to a state of unrestricted use. The charges to income are based on estimates determined through studies of these future costs. Periodic reviews will be carried out to evaluate the accuracy of these cost estimates and any changes will be implemented on a prospective basis."

2.4 Applications to the Board

The Board has received four applications from companies under its jurisdiction for the provision of negative salvage funds, as follows:

2.4.1 Trans-Northern Pipe Lines (TNPL)

As part of its 1981 toll application, TNPL filed a depreciation study which included a provision of approximately $2 million (1981 dollars) for negative salvage. Parts of this study were heard during the hearing, but TNPL indicated that although it supported the concept of negative salvage it had neither the experience nor the evidence to support the amount and consequently decided to exclude the negative salvage provision.

2.4.2 Trans Québec & Maritimes Pipeline Inc. (TQM)

With its toll application of August 1983, TQM filed a depreciation study prepared by Stone & Webster (and the related direct evidence of R. Bird). The depreciation rates calculated in the study took into account negative salvage for certain assets. Negative salvage totalled about $60 million (1982 dollars).

Before the matter came up for discussion in the hearing, however, TQM withdrew those aspects of its application which related to negative salvage.

2.4.3 TransCanada PipeLines (TCPL)

TCPL filed, for the approval of the Board, a depreciation study which took into account negative salvage of approximately $447 million (1982 dollars). In its toll application of January 1984, however, TCPL did not apply for a change in depreciation rates to reflect negative salvage. The Hearing Order stated that the negative salvage aspects of the depreciation study would not be considered in the hearing since time did not permit adequate consideration of this issue.

2.4.4 Westcoast Transmission Company Limited (WTCL)

Pursuant to the Board's Decision of August 1983, WTCL submitted a depreciation study to be considered during the Methodology Hearing. The study includes a provision of $268 million (1984 dollars) for negative salvage. It is discussed in more detail below.

2.5 The Westcoast Methodology Hearing

The Westcoast Methodology Hearing was unique in that it was the first (and to date, only) instance in which the Board has examined in some detail the principle of negative salvage, during a Hearing. This occurred as a result of the Hearing Panel's decision that it would be an appropriate time to examine the depreciation study filed by Westcoast in March 1984. This depreciation study suggested new depreciation rates and gave details on the derivation of those rates, but Westcoast did not apply for a change in the rates currently used. The Company had included provision for negative salvage in its derivation of the new depreciation rates. In response to concerns from some of the Interested Parties to the Hearing, the Panel agreed to limit the discussion of the negative salvage component of the depreciation study to the relevant principles only. This had the effect of limiting the scope of cross examination on the details employed by Westcoast to derive the negative salvage cost estimates. However Westcoast provided working papers utilized on negative salvage cost estimates for each of its pipelines, compressor stations, and processing plants. These working papers provide valuable insight into cost estimating for negative salvage.

Initially Westcoast estimated that the entire cost of negative salvage in 1984 dollars was $268 million. This estimate provided for the removal of all pipe, compressor stations and processing plants. Subsequently, in response to an information request, Westcoast indicated that under the constraint of minimizing costs, negative salvage on their system could be reduced to $119 million (or $133 million after providing for perpetual maintenance costs at 3 percent real interest*). Its second estimate provided for the removal of compressor stations, processing plants, and aerial pipeline crossings but anticipated the abandonment in place (with perpetual annual maintenance costs of $577,000), of all pipelines. Finally, Westcoast was requested to provide a negative salvage cost estimate under the constraints of least cost, land use, environmental, and safety criteria. In response to this request the Company submitted an estimate of $127 million (or $141 million after providing for perpetual maintenance costs at 3 percent real interest*). Its third estimate was arrived at in an essentially identical manner as the $119 million estimate discussed above, except that all above ground facilities were to be removed including valves, pig traps, and other above ground pipe assemblies. It should be noted that Westcoast submitted the latter two estimates under the assumption that the Board would

* See also section 4.2 of this report

relieve the Company from the pipeline removal obligations included in the gas pipeline regulations. During the course of the Hearing the Company did not put forward any one of its three cost estimates as being a 'base case'. Neither did it submit any studies to demonstrate the viability of abandoning all of the pipelines in the ground with perpetual maintenance.

With regard to the financial issues, the Company stated that it was prepared to seek a favourable ruling from the Department of National Revenue for the income tax treatment afforded to the negative salvage funds collected. Furthermore, Westcoast was not opposed, in principle, to the use of an external trust fund for the management of the negative salvage revenues.

In general the Interested Parties seemed to be opposed to the commencement of the collection of negative salvage funds at this time. It should be noted, however, that the Interested Parties did not include representatives of the general public such as municipalities, farm associations, or individual land owners, to whom the marginal incremental costs, represented by the inclusion of negative salvage in Westcoast's cost of service, may be more than offset by the security offered by a preconceived abandonment plan for Westcoast's facilities.

In its decision of April 1985, the Board's conclusions relating to the provision of negative salvage revenues were that "... because of the complexity of this subject, further study and assessment is required."

Chapter 3
Physical Aspects

3.1 Requirements of the NEB Pipeline Regulations

The NEB Oil Pipeline Regulations and Gas Pipeline Regulations are currently under review. The revised document is called the Onshore Pipeline Regulations. A new document, the Offshore Pipeline Regulations, is also being written. Drafts of these documents are being reviewed by industry. Their comments will be considered when the Board adopts the regulations.

The requirements of the existing and proposed regulations relating to pipeline abandonments, (See Appendix II) appear to assume the continued existence of the company after the abandonment, therefore the applicability of these regulations in the event of the termination of a company following abandonment of all of its facilities in place, merits further consideration. Indeed, because the current regulations respecting abandoned pipelines are so central to the whole issue of negative salvage, there may be merit in providing for changes in the regulations as the perception of the technical, environmental, land title, and cost aspects of abandonment continues to evolve.

3.2 Overview of the Pipeline Facilities under Board Jurisdiction

As of January 1985, over 27,500 km of gas and oil pipelines, ranging in diameter from 50 mm to 1220 mm, fall under the Board's jurisdiction (See Appendix III). The pipelines are operated by thirty-nine companies. All lines are underground except for the 146 km of 114.3 mm diameter pipeline operated by Yukon Pipelines Ltd.

The Board also regulates above ground facilities including approximately 192 compressor/pump stations, 4 gas or oil processing plants, 15 miscellaneous storage and terminal facilities, and over 200 meter stations (See Appendix IV).

3.3 Engineering Considerations

3.3.1 Below Ground Facilities

Controlling Pipe Corrosion

Corrosion is an electrochemical process requiring a metallic connection between two electrodes which are immersed in an electrolyte. These components form a reaction cell. Reaction cells are often created between buried steel pipe and ground water. Strong electrolites associated with acid soils can produce highly corrosive situations.

In order to prevent corrosion of steel, the electrochemical reaction cell must be broken. For pipelines the application of a layer of insulating material on the pipe surface is used to prevent physical and electrical contact between the steel and the electrolyte. Many different materials may be used including fusion bonded epoxy, extruded polyethylene, polyethylene tape, and coal tar enamel. Insulating barriers provide a high degree of protection, however due to the likelihood of mechanical damage, and defects in application, they are not perfect. Electrical methods are also used to prevent corrosion. Since metal loss during corrosion always occurs in the anodic zone, protection can be achieved by attaching sacrificial anodes to the pipe, or by externally applying a voltage to the pipe making it cathodic with respect to its surroundings. These electrical methods for corrosion prevention are known as "cathodic protection".

A correctly applied and undamaged pipe coating, along with a properly designed and operated cathodic protection system, ensures that the serviceable life of a buried pipeline is not limited by the effects of corrosion.

Abandonment Considerations

Three basic options are available for the ultimate disposition of buried pipeline facilities, abandonment in place, abandonment with the maintenance of cathodic protection and inert fill, or removal.

Pipelines abandoned in place without the maintenance of cathodic protection will corrode at a rate dependent on site conditions. This rate is impossible to predict. A thick walled pipe coated with epoxy and in a mildly corrosive location may last for decades, while a poorly coated, thin walled pipeline in a highly corrosive environment may corrode and collapse in less than a decade.

The consequence of pipe collapse in the case of small diameter pipelines (10" or less) would be mini-

mal since the amount of surface subsidence would be small. Collapse of a large diameter pipeline, particularly in an environmentally sensitive area, would require that the resulting surface depression be backfilled and restored.

Monitoring abandoned large diameter pipelines for collapse over a long-term time period would likely be unattractive to most companies. A possible solution would be the development of a tool that could be used to collapse the line upon abandonment. It may be possible to develop such a device by combining proven technologies such as internal crawlers, pigging, and automatic cutting instruments. It therefore may be feasible to use a tool to induce pipe collapse by crawling through the buried pipeline while making three or more circumferentially spaced longitudinal cuts. (It is assumed that if this concept was ever seriously pursued, reasonable safety precautions governing its use would also be developed.) Right-of-way restoration could then proceed immediately and once completed, the company could be absolved of the requirement for long term monitoring. (In order to effect a satisfactory restoration of the right-of-way topsoil separation prior to pipe collapse and compaction of the remaining soil over the pipe after its collapse, may be desirable.)

A second possible solution to simplify the abandonment procedure and prevent pipe and soil collapse would be to fill the pipelines with a fluid mixture that would solidify. This approach might be applicable in situations such as large diameter crossings where it would be less expensive to fill the pipeline with a solid, to prevent soil settlement under the crossing, than to remove the pipeline. The solid fill procedure would also be desirable for extended lengths of pipe if it could be done less expensively than pipe removal. The technical feasibility and cost of the solid fill abandonment procedure should be addressed whenever the removal of below ground pipelines is proposed. Although the cost advantages of solid fill versus removal may be most significant for long lengths of pipe, it is here, with the probable elevation variations and injection power requirements, that the feasibility is most in doubt. It would be desirable to monitor the results of any research on the filling of pipelines with solids, to ensure that less expensive alternatives to pipe removal are provided for, as they are developed, in the negative salvage cost estimates.

Maintaining cathodic protection on pipeline systems that have been abandoned in place may be appropriate in certain circumstances. The principle advantage of this would be to indefinitely delay the collapse of the pipe. This would extend the time period during which an alternative use could be sought for the pipeline. Before the abandoned pipeline was placed into an alternative use however its integrity would probably have to be re-established by strength testing. Nevertheless, any possibility of extending the life of a pipeline by finding a future alternative use would be an argument for continuing to protect the integrity of the line.

In recent years only one pipeline removal operation has taken place under the Board's jurisdiction. In October 1980, Interprovincial Pipe Line removed a 3.2 km section of 864 mm O.D. pipeline from the right of way on an experimental basis. IPL concluded that such removal was technically feasible, even when the line to be removed shares the right of way with one or more "hot" pipelines. The methods used for removal were analagous to those used for construction although there is a different magnitude of sophistication involved. IPL concluded that the costs involved make abandonment in place (with maintenance) preferable to pipe removal in the majority of circumstances.

3.3.2 Above Ground Facilities

Above ground facilities such as meter stations, pump or compressor stations, storage facilities, and processing plants, require specific disposal consideration following abandonment of a pipeline. Furthermore, specific types of above ground facilities would require separate analysis since the salvage value of each type of equipment as well as the removal costs would be unique.

Generally, removal costs for above ground piping and equipment would tend to be much lower than those for buried pipe (on a ton of steel versus ton of steel basis). Consequently, negative salvage costs could be low and indeed positive salvage value may be possible in certain cases. Buildings may be sold if they remain structurally sound and if they are suitable for alternative uses.

The decommissioning and removal of above ground pipeline facilities should be similar in many aspects to that of other kinds of petrochemical plants. One ongoing example is the 'removal' of the Petrocan (formerly British Petroleum) refinery in Montreal.

3.4 Environmental Considerations

The overall environmental consideration for any project is to properly assess both its positive and negative impacts. Procedures may then be devised to capitalize on the positive aspects and mitigate negative impacts. In addition any residual negative impacts which remain, after the mitigative measures have been implemented, must be considered in the decision to allow a project to proceed. This rationale,

which the Board already uses in its consideration of pipeline construction projects, should also be used in the consideration of abandonment of facilities.

One environmental comment that applies to all pipeline facilities abandoned in place, is that preventative measures should be taken to ensure that they are cleared and purged prior to abandonment. This will have the dual effect of preventing the possible contamination of soil, ground water, or surface water regimes and reduce the possibility of gas formation within the pipe.

3.4.1 Below Ground Facilities

With respect to short-term impacts, removal of facilities would likely have a greater environmental impact than abandonment in place. However, the long-term effects of the collapse of large diameter pipe, left in place, are likely to be significant.

Pipe Removal

The removal of pipelines will likely involve many tasks similar to those for pipeline construction in the same area. Environmental considerations for the removal operation will also be similar to those for the original construction if land use and environmental factors of adjacent areas have not changed considerably during the operational life of the pipeline. In considering the effects of abandonment, the environmental impact statement submitted with the original application to construct the facilities should be a starting point. Potential environmental concerns would include:

(a) topsoil preservation,

(b) soil compaction,

(c) drainage, disruption, diversion and erosion

(d) water crossings - stability, scheduling, and siltation

(e) backfill requirements,

(f) stabilization, and

(g) restoration.

A major environmental and engineering issue would be the source of materials for the backfilling of the trench once the pipe has been removed. As the volume of material required for fill increases as a function of the square of the pipe diameter, the fill costs associated with the removal of large diameter pipe may be considerable.

Inground Abandonment

Consideration must be given to the outright abandonment of pipelines in the ground due to the high cost of removal. Assuming that cathodic protection of the pipeline is not maintained, its collapse at some undetermined time can be anticipated. If the pipeline has not been filled with solids prior to its collapse, then ground settlement will follow.

Depending on the diameter of pipe, depressions would form along the right-of-way as the abandoned pipe collapses. Pipe collapse could in certain types of terrain lead to:

(a) top-soil erosion,

(b) flooding of adjacent areas,

(c) diversion of surface waters along the right-of-way,

(d) disruption of agricultural activities,

(e) terrain disturbances in sensitive areas, e.g. permafrost, stream crossings,

(f) danger and disruption to wildlife and their habitat, and

(g) disruption of other facilities at crossings.

Pipelines of 168 mm (6") diameter or less, even if completely collapsed, would likely not result in any detectable depression along the right-of-way.

Medium size pipelines 219 mm (8") and 355 mm (14") would likely create some disturbance upon collapse, mainly in environmentally sensitive sections of the line. It would likely be necessary to backfill and seed some sections of the line.

For large diameter pipeline between 406 mm (16") and 1200 mm (48") the environmental implications of abandoning in place would likely be severe. It is anticipated that eventually it would be necessary to restore large portions of the right-of-way. The uncertainty of when this will occur and of who will be responsible for the restoration of the right of way after its occurrence, are arguments in favour of either removal or of inducing the early and controlled collapse of the pipeline.

Table 3.4.1 summarizes the generally expected environmental impact associated with the removal and outright abandonment of pipelines as a function of different terrain and hydrogeological conditions.

Table 3.4.2 sets out the type of pipeline abandonment procedures that may be generally appropriate for the range of pipe diameters, land uses and crossings considered. The unproven techniques of solid fill and controlled pipe collapse have not been included in the procedures set out in this Table.

Table 3.4.1
Impact of Abandonment Techniques on Various Terrain Types

Land use or terrain type	Impact of removal	Impact of pipe collapse if pipe left inground	Comments
Agricultural Land	High Impact - similar to construction Mitigative measures the same or similar to construction.	Depression so formed may cause ponding of surface water, redirection of drainage and increased soil erosion; these effects will vary with soil type and according to slope and soil stratigraphy For example ponding may be a problem on heavy clay loams while erosion is more likely to be a problem with sandy soils.	Induced collapse may be desire-able for the landowner, pipe-line company and the regulator as the possible problems are dealt with early and in a controlled manner. Additional impacts such as in filling depressions where required can also be dealt with expeditiously. Note, the depth and extent of the depressions is a function of pipe diameter vs depth of cover and soil type. (Shear strength and cohesion are the principal considerations in determining the soil behaviour in this situation.)
Wetlands, Muskeg, Marsh and Swamp, etc.	Requirement to remove low and cost high. Operations best done in winter when terrain is frozen. Impacts similar to construction.	Initially the pipe may float. This could be avoided by injection with H_2O. Impact of corroding and collapsed pipe probably very low	Leave in ground, clean internally and inject with H_2O or flood pipe by drilling holes. Prevent pipe floatation.
River Crossings	High impact, and high cost. Removal probably not necessary. Impacts similar to construction.	When the pipe collapses, the trench will fill gradually and naturally with bottom sediment. Impact of collapse is very low Erosion of the river banks and bottom may expose the pipe	Prevent pipe floatation, leave inground, flood with H_2O as for Wetlands above.
Rock and Thin Veneers of Soil over Rock	Low terrain impact; however, interrupted and redirected drainage may produce high impact on adjacent terrain Cost high.	Collapsed trench will collect surface water. The ditch is relatively impermeable. On flat terrain ponding will occur. On steep terrain intercepted drainage will be directed along trench; velocity of water may be extreme.	Energy dissipators in the collapsed trench may be required. Water exiting from trench on to erodable terrain may cause serious erosion Erosion potential of ditch itself is low.
Fine Grained Soils (Silts and Clays)	Variable - but similar to construction.	Impermeability of soils is a controlling factor. On steep slopes terrain instability is a major consideration.	Impact is dependent on slopes, ground and surface water regimes, type of clay and associated substrata. Terrain may be unstable and subject to erosion. On flat lying terrain ponding of water is a major consideration.
Coarse Grained Soils, (Sand and Gravel and Sandy Soils)	Variable but similar to construction.	Probability of erosion ranges from medium to high for sands. Erosion is also dependent on slope	On easily erodable soils flow-ing water is likely to be a major problem. Soil permeability may vary widely

Table 3.4.2
Negative Salvage Options

	Rural lands						Urban lands				
	Agricultural		Non-Agricultural								
Pipeline Size	Crop	Pasture	Rock	Till	Cohesive Soil	Granular Soil	Wetlands	Suburban	Park	Urban	Industrial
102 mm (4")	A	A	A	A	A	A	A+	A	A	A	A
153 mm (6")	A	A	A	A	A	A	A+	A	A	A	A
203 mm (8")	A	A	A	A	A	A	A+	A	A	A	A
273 mm (10")	R	A	A	A	A	A	A+	A	A	A+	A+
323 mm (12")	R	A	A	A	A	A	A+	A	A	A+	A+
356 (14")	R	R	A	A	A	A	A+	A	A	A+	A+
406 (16")	R	R	A	A	A	A	A+	A	A	S	S
550 (20")	R	R	A+	A+	A+	A+	A+	A+	A+	S	S
610 (24")	R	R	A+	A+	A+	A+	A+	A+	A+	S	S
762 (30")	R	R	A+	A+	A+	A+	A+	A+	A+	S	S
914 (36")	R	R	A+	A+	A+	A+	A+	A+	A+	S	S

LEGEND:
A Abandonment recommended
A+ Abandonment with additional treatment recommended
R Removal recommended
Special considerations - site-specific evaluation required

Table 3.4.2 (Cont'd)
Negative Salvage Options

Pipeline Size	River	River Approaches	Rail	Crossings Road	Sec. Road	Pipeline	Sewer	Cable
102 mm (4")	A	A	A	A	A	A	A	A
153 mm (6")	A	A	A	A	A	A	A	A
203 mm (8")	A	A	A	A	A	A	A	A
273 mm (10")	A	S	A+	A+	A	S	A	A
323 (12")	A+	S	A+	A+	A	S	A	A
356 (14")	A+	S	A+	A+	A+	S	A+	A
406 (16")	A+	S	A+	A+	A+	S	A+	A+
550 (20")	A+	S	A+	A+	A+	S	A+	A+
610 (24")	A+	S	A+	A+	A+	S	A+	A+
762 (30")	A+	S	A+	A+	A+	S	A+	A+
914 (36")	A+	S	A+	A+	A+	S	A+	A+

LEGEND: A Abandonment recommended
A+ Abandonment with additional treatment recommended
R Removal recommended
Special considerations - site-specific evaluation required

3.4.2 *Above Ground Facilities*

To the general environmental considerations which apply to both above and below ground pipeline abandonments the following comments with respect to above ground facilities can be added.

The remaining in place abandoned facilities may compromise future land use development of these areas. In order to avoid long-term environmental, aesthetic, land use, and regulatory problems it would be generally considered a good practice to remove all above ground facilities and restore the abandoned sites.

3.5 Land Title Considerations

Land rights obtained by the company for above-ground facilities include: fee simple (lands purchased outright); leasehold lands (land rights held for a specified period of time); and easements (certain land *rights* held in perpetuity and subject to relinquishment). Facilities like compressor and pump stations, gas plants, tankage and storage, and certain meter stations are normally located on either fee simple or leasehold lands. Lines of pipe, sales taps and safety valves are usually located within the limits of acquired easements. Certain easement agreements however, may provide specific allowance for above ground structures.

3.5.1 *Below Ground Facilities*

Easements

Companies normally secure easements across private and crown lands for the location of their buried pipelines and certain above ground structures. Easements have generally included provisions for - the laying down, construction, operation, maintenance, inspection, alteration, removal, replacement, reconstruction and/or repair of the facilities. Further, provision has been made for the abandonment and release of the rights provided that the grantee (the company), if it so elects, leave the pipe or any part thereof in place. Provision has also been made for the restora-

tion of and compensation for any damages resulting from the activities of a company

Prior to 1 March 1983, the proclamation date of Bill C-60, the retirement of a general plant would have been relatively straightforward. Easement agreements were secured by lump sum payment. Facility retirement, therefore, would only incur the future legal costs associated with relinquishing easement rights, and the further expenses resulting from damage and restoration regardless of whether the line of pipe was being removed or abandoned. The assumption is made that a company would still be responsible for any pipelines abandoned-in-place, where the easement rights had been surrendered. On the other hand, it is possible that the Board could allow a company to sell the pipeline to the respective landowner, thereby alleviating any responsibility for future damages and restoration.

Subsequent to 1 March 1983, amendments to the NEB Act require that an owner of lands granting an easement be presented with the option to receive a lump sum, annual or periodic payment for the land rights granted. Settlements agreed to under the latter two categories will be reviewed every five years. No company yet has entered into such easement agreements, so it is difficult to determine their future plant retirement policies that will be included in them. Similarly, it is not possible to determine whether new easement agreements would include any specific provisions for premature plant retirement.

Certain easement agreements do not allow abandonment-in-place, but require removal. An example is the case of an early easement agreement held by Petroleum Transmission Company. In those situations, therefore, funding provisions for future plant retirement would have to consider only removal. Similarly, the provision of Westcoast's crown easement requires that the lands be left in a "safe condition satisfactory to the grantor". Certain costs may be involved in meeting that condition.

3.5.2 *Above Ground Facilities*

Fee Simple Lands

Facilities located on fee simple lands were approved originally by either a certificate of public convenience and necessity or an order. That approval allowed a company to locate its above ground facilities, which could be considered as an industrial land use, within other land use areas, e.g. agricultural, forest or residential. In many instances, this usurped to a degree the normal planning process which provides for the orderly planned location of similar land uses.

The determination of whether to remove or abandon above ground facilities located on fee simple lands must include a decision on whether it is desirable to attempt to reverse the land use intrusion caused by the facility, by removing it and attempting to restore the land to its original condition. If land use reversal is not considered necessary then consideration should be given to the market which exists for buildings located on the fee lands, prior to deciding to remove them.

Leasehold Lands

Leasehold lands are generally located within crown lands. Crown lands, while not normally subject to stringent land use designations, may be influenced by federal/provincial policies and programs for land uses such as agriculture, recreation, forestry or mining. Facilities located within areas that are governed by compatible federal/provincial policies may also have conversion potential.

Any provision for abandoned property becoming part of crown assets, similar to the previously cited Crown - Westcoast Transmission Company Limited easement, may influence retirement costs as the leaseholder has the option of removing any plant facilities or leaving them in place. In the latter situation, those facilities may then become the property of the crown. In any event the lessee must leave its lands in a "safe" condition satisfactory to the lessor. The Board may wish to consider the lessor's opinion at the time of salvage and at the time that negative salvage costs are considered.

Easement Lands

In the case of easements, the decision to remove above ground structures would be governed in part by the NEB Act, in part by the current land use and, above all, by the easement agreement. The principal land use consideration when dealing with the removal or abandonment of small scale above ground structures should be the convenience of the landowner. Common sense would suggest that in areas that involve a lot of surface activity, such as agricultural lands, the removal of above ground facilities would appear to be appropriate. However the same may not hold true for forested land or lands that are remote from human activity. All other implications related to easement agreements are covered in.section 3.5.1.

3.6 Possible Future Alternative Uses for Abandoned Facilities

Several potential uses for abandoned pipelines can be envisaged including transporting water, grain, mineral slurries, and future fuels, as well as providing sleeves for fiber optic telecommunication lines. Cer-

tain above ground facilities such as buildings also may have potential future uses. No future alternative uses have yet been proposed however, this possibility should continue to be investigated from time to time in the future.

If an alternative use is eventually found for a pipeline it is appropriate to consider what would happen to the funds already collected for negative salvage. This scenario raises the possibility of a positive salvage value for the pipeline, relative to its current purpose, if it is sold to serve another function. If one accepts the premise that ultimately negative salvage for pipelines will be necessary, no matter how long their useful life is extended by alternative uses, then if the collected funds are controlled by a third party (i.e. external trust), these funds could be held until the useful life is finally truly exhausted. Therefore, the potential for future alternative uses for pipelines does not imply that it is premature to commence the collection of negative salvage at an early date.

Chapter 4
Cost Estimating

The purpose of this section is to summarize cost information relating to above and below ground facility abandonments and to draw some conclusions from the information. This may be of some assistance in assessing future abandonment cost estimates.

4.1 Actual Historical Abandonment Costs

4.1.1 Abandonment Costs for Removal

One well documented example of a pipeline abandonment by removal, under the Board's jurisdiction, is the 1980 IPL abandonment project. This project involved the abandonment of 23.8 km of 864 mm x 7.14 mm pipe. On an experimental basis IPL removed 3.2 km of this pipe in an attempt to learn more about removal procedures and costs.

The removal costs for this project were approximately $180,000 for the contractor and $20,000 for oil removal and the survey crew (all amounts are in 1980 $). The total of $200,000 is equivalent to about $62,300/km.

The salvage prices which the Company negotiated for the used pipe were between $100 and $200 per ton (or 17 to 34 percent of the replacement value). This reflects the fact that the purchaser intended to reuse the pipe. IPL estimated that if the pipe had been sold for scrap to a steel mill then the salvage value would have dropped to between $70 and $80 per ton (or 13% of the replacement value). These figures are based on a weight for this type of pipe of 166 tons/km.

The net negative salvage for this project is estimated to be $120,000, or $37,600/km. However if IPL had been forced to sell the pipe for scrap then the net negative salvage would have been about $50,000/km. While it is reasonable to expect that a removal project of a larger magnitude could achieve, through economies of scale, lower unit removal costs, some of this saving would be offset by the likelihood of having to sell the pipe for scrap instead of for use.

The best example involving the abandonment by removal of above ground facilities, under the Board's jurisdiction, is the 1983 Trans Mountain pump stations abandonment. This project, heard by the Board during the 1983 Toll Hearing, anticipated the removal of 11 pump stations for a total of $540,000 (1983 $) or $50,000/pump station. The Company indicated that the pump stations were redundant, unattended and were responsible for significant routine maintenance and vandalism costs.

4.1.2 Abandonment Costs for Facilities Left in Place

Numerous sections of underground pipelines have been abandoned in place by pipeline companies under the Board's jurisdiction. All of these cases are thought to have provided for continuing maintenance (i.e.: seal, fill with inert gas, cap, continue cathodic protection and include in annual pipeline surveys).

Although not generally required by the Board in the past, the historical costs associated with these abandonments could probably be provided by companies. Evidence given in the recent Westcoast methodology

Table 4.1.2

WTCL Unit Cost Estimates for Filling Abandoned Gas Pipelines with Nitrogen

Pipe Diameter (mm)	Cost/Km (1984 $)
101.6	40
114.3	70
168.3	85
219.1	114
273.1	189
323.9	234
406.4	304
457	345
508	385
610**	540
660	599
762*	657
914*	1,004

* For comparison, as part of its 1980 pipeline abandonment project, IPL experienced costs of $3,400/km (1980 $) to remove the oil and fill the 864 mm section with nitrogen.

** For comparison, TCPL estimated costs of $4,661/km to do the same thing in their 1982 Niagara abandonment application

hearing provided the unit cost estimates for filling abandoned pipelines with nitrogen, these are shown in Table 4.1.2. In addition, Westcoast estimated a continuing maintenance cost of $130/annum/ km*. The latter cost is equivalent to a lump sum of $4,333/km (1984 $) assuming 3% *real* interest in perpetuity.

The cost to abandon underground facilities in place without maintenance would probably amount only to the cost to remove dangerous fluids from the pipe and to fill it with nitrogen. An additional allowance of funds to provide warning signs might be desirable.

4.2 Cost Estimates Included in Submissions to the Board

Six companies have made submissions to the Board respecting cost estimates for the negative salvage of facilities. Details of these submissions follow and they are summarized in Table 4.2.

4.2.1 IPL

On the basis of its experience with the removal of 3.2 km of pipe in 1980, IPL submitted an estimate of the cost to remove a minimum of 50 km of 864 mm x 7.14 mm pipe. Their results (in 1980 $) provided unit negative salvage values for this type of pipe of $25,000/km. This was computed from an estimate of $37,000/km to remove the pipe and a salvage value of $12,000/km for the pipe assuming it is sold for scrap. The latter utilizes a scrap value of about $75/ton.

4.2.2 TNPL

During the Company's 1981 Toll Hearing a study was prepared by Stone and Webster which recommended the collection of 2 million dollars for the negative salvage of the pipeline. Given that the Company has 894 km of pipeline, this estimate works out to a unit value of only $2,250/km. No further information or background documents were provided and the issue was dropped during the hearing. Therefore this estimate is totally unreliable as it is not even known whether it referred to abandonment in place or by removal.

4.2.3 TMPL

During the 1983 TransMountain toll hearing the company applied to remove and abandon eleven of its pump stations. The cost for this work was estimated to be $540,000 or about $50,000/pump station. This cost was intended to include the removal of the facilities as well as site restoration but details about the size of the facilities to be removed are unknown at this time.

4.2.4 TQM

In its toll application leading up to the 1984 toll hearing the Company provided for $60,900,000 of negative salvage in arriving at new depreciation rates. This was totally imbedded in the mains account and amounts to approximately $180,000/km.

In a response to a request from CPA to indicate how this amount was arrived at, the Company provided its calculation procedures and assumptions. These involved detailed estimates of the crew requirements, wages (Decree rates and N.P.A. rates), contractor move-in and move-out costs, fill costs, contractors' overhead and profit, additional temporary land costs, land damages, meter station and hot tap removals, and an eight per cent contingency. The total removal costs of between 80 and 100 million dollars (under various assumptions) did not agree with the 61 million dollar estimate provided in the application and is substantially greater, on a unit cost basis than the estimates provided by WTCL, TCPL and IPL. (Note: IPL's estimates were based on actual removal experience). Furthermore, TQM's estimate did not allow for any scrap or resale value for the pipe.

This issue was dropped prior to the commencement of the hearing and thus none of the inconsistencies in TQM's estimate were questioned.

4.2.5 TCPL

In its 1984 toll hearing TCPL provided an allowance of 447 million dollars of negative salvage, in seeking new depreciation rates. In response to a question from the NEB it was explained that this amount was based on a previous 1982 TransCanada study and then escalated to account for the subsequent growth in rate base.

The previous 1982 TransCanada study, referred to above, arrived at a total negative salvage estimate of 321 million dollars (1982). This estimate included pipeline removal costs of 660 million dollars ($62,000/km) and a pipe salvage value of 351 million dollars ($33,000/km) for various sizes of large diameter pipe. The latter was based on a scrap value of about 136 $/ton. (This seems high compared to the IPL experience discussed in section 3.1.) TCPL also estimated unit removal costs and salvage values for the compressor stations of $400,000/station and

* For comparison, TCPL estimated annual maintenance costs not including leak detection and repairs, of $187/annum/km for 610 mm pipe, in their 1982 Niagara line abandonment application. This, despite the fact that they would continue to operate parallel lines for many years

$160,000/station respectively. It is interesting to note that they utilized salvage values of $107/ton and $117/ton for reciprocating stations and turbine stations respectively but $270/ton for electric stations.

Once again this matter was dropped prior to the hearing, thereby eliminating the opportunity for clarification of these matters.

4.2.6 WTCL

Negative salvage estimates provided by Westcoast were discussed during the Company's recent methodology hearing. These estimates were provided by the Company, as follows:

(i) The first estimate included in Westcoast's March 1984 depreciation study amounted to 268 million dollars (1984). This can be broken down into 82, 22, and 164 million dollars for process plants, compressor stations, and removal of all pipelines, respectively. Working papers were submitted to support these estimates.

In arriving at the unit pipeline negative salvage costs of $37,000/km Westcoast appears to have taken into account all of the removal considerations addressed by TQM. As well, Westcoast made an allowance of generally $40/ton, for freight costs for the salvaged pipe. The Company has utilized relatively conservative salvage values for the steel of $40/ton, delivered. For the gathering lines, however, Westcoast assumed zero salvage value probably on the expectation that sulphur-contaminated steel would not be marketable. Therefore, the average salvage value is only $29/ton. The average removal cost is $35,000/km.

Similar procedures were used by Westcoast for compressor stations and processing plants. However, in the calculation of salvage costs for the compressor stations, Westcoast assumed zero salvage value for the equipment, and no explanation was given for this. Westcoast's estimates show a wide variation in salvage costs on a station by station basis, probably as a function of relative size. Their costs for compressor station removal range from $375,000 to $1,750,000. A salvage value of $10/ton (after shipping) was assumed for the value of steel from the processing plants.

(ii) The second estimate provided by Westcoast was identical to the first except that only the aerial crossing portions of the pipeline were to be removed. The balance was to be capped, filled with inert gas and perpetually maintained. After converting perpetual expenditures to current dollars at 3% *real* interest this amounts to a unit cost of $6,400/km.

(iii) The third estimate provided by Westcoast was the same as the second except that, for safety considerations, removal of above ground fabricated assemblies was assumed. This increased the unit cost to $8,300/km.

Table 4.2
Summary of Plant Abandonment by Removal Unit Cost Estimates

Company	Year of Dollars	Unit Costs		
		Pipeline ($/km)	Stations ($/Station)	Processing Plant ($/Plant)
I.P.L	1980	25,000		
TNPL	1981	2,250		
TMPL	1983		50,000	
TQM	1982	180,000		
TCPL	1982	29,000	245,000	
WTCL (i)	1984	37,000	760,000	27,300,000
(ii)	1984	6,400	760,000	27,300,000
(iii)	1984	8,300	760,000	27,300,000

A comparison of the estimates for removal to cost estimates for construction (generally over a million dollars per kilometre for large diameter pipe), demonstrates a difference of more than one order of magnitude. Some difference is obviously expected due to the reduced standards and levels of complexity associated with pipe removal versus construction. However, many of the construction techniques (i.e.: ditching for example) are also utilized for pipe removal. Therefore, notwithstanding IPL's actual pipe removal experience, there is a concern that the removal costs being estimated may be somewhat low.

4.3 Consistent Criteria for Assessing Abandonment Cost Estimates

The wide range in estimates evident for the abandonment of pipelines in place and abandonment by removal suggests that the approach used by companies to prepare the estimates are generally inconsistent.

For estimates of the cost of abandonment-in-place, the range that cannot be explained may be fairly small. Company-held historical records may shed light on the reasons for the discrepancies that do exist. However, the range in cost estimates for abandonment by removal is far greater, less easily explained, and there is little historical information. Unit cost estimates for the removal of above ground pumping or compressor stations range from $50,000/sta-

tion to $760,000/station. Some parts of this variation can be explained by size, but size alone does not contribute to this magnitude of difference. For below ground facilities removal cost estimates range from $2,250/km to $180,000/km, although three separate estimates seem to converge in the $30,000-$40,000/km range (1984$).

A complete set of consistent criteria with which to measure cost estimates may evolve over time. The following points are a start.

i) Pipe Salvage Value: Five-year average market scrap steel prices could be used for removed pipeline. This would help ensure consistency and will also dampen the large fluctuations in scrap steel prices. Estimates could also be obtained for sulphur contaminated steel and investigations begun to determine whether this product can be made more marketable.

ii) Compressor Station and Process Plant Salvage Values: Similar procedures to estimate salvage value could be utilized for these facilities. It should be remembered that in some instances part of the plants or stations considered may have sulphur contaminated steel (i.e. Westcoast). Explanations for the high salvage value of electric engines should be sought.

iii) Industry consensus on labour requirements: It might be useful to seek an industry consensus on the labour requirements and costs for the removal of typical compressor stations and pipelines.

iv) Land Value: The value of land owned by a company should be estimated and credited against negative salvage costs.

v) Buildings: Above ground facilities should be checked to see whether the buildings have long-term alternative uses. If so, the value should be estimated and credited against negative salvage costs.

4.4 Differences in Above and Below Ground Facilities Abandonment Cost Estimates

Estimates submitted to the Board demonstrate substantially lower total costs to remove above ground facilities than to remove below ground facilities. An example of this is the TransCanada system where one estimate for the removal of their compressor stations amounted to $12 million as opposed to $309 million for below ground facilities. Generally this situation is expected to be representative of the industry as a whole. One exception is Westcoast, where estimates for above ground negative salvage are $104 million versus $164 million for below ground. This is due to the presence of three very large processing plants on the Westcoast system and high unit negative salvage estimates for compressor station removals.

A second difference is the degree of consensus over the necessity for the removal of above and below ground facilities. While consensus may be readily available regarding the necessity for the removal of above ground facilities, it is expected that it will be more difficult to achieve consensus regarding below ground facilities. Furthermore, decisions relating to below ground facilities are more likely to be subject to change in the future as a result of further research, population encroachment, land development, cost of service, or other considerations. The possibility for major changes in the scope of pipeline removal will make it difficult to have a high degree of confidence in estimates of final costs.

4.5 The Magnitude of Negative Salvage Estimates Relative to Cost of Service

Table 4.4.1 demonstrates the magnitude of three companies' negative salvage estimates relative to currently approved cost of service. This has been done for the first year assuming 100 percent of their above and below ground removal costs were accepted by the Board and permitted to be recovered over a 30-year period on a straight line basis.

Table 4.4.1
The Cost of Providing Negative Salvage Funds in the First Year Relative to the Current Cost of Service (100 percent of removal costs accepted) $000,000

	Negative Salvage Estimate			
Company	Total	First Year* (A)	Approximate 1984 Cost of Service (B)	A/B%**
TCPL	447	15	1,021	1.5
TQ&M	61	2	38	5.3
WTCL	268	9	274	3.1

A more probable scenario is one in which the Board authorizes removal of all above ground facilities but only about 20 percent of below ground pipe, with an allowance for perpetual maintenance for the remainder. Table 4.4.2 demonstrates this scenario using 30 percent of below ground removal cost estimates.

* This 'ball park' estimate does not make provision for the effects of inflation, interest, or tax in the calculations

** Results for more fully depreciated pipeline companies will be higher

Table 4.4.2
The Cost of Providing Negative Salvage Funds in the First Year Relative to the Current Cost of Service (30 percent of below ground and all above ground removal costs) $000,000
Negative Salvage Estimate

Company	Total	First Year* (A)	Approximate 1984 Cost of Service (B)	A/B %**
TCPL	146	4.9	1,021	0.5
TQ&M	18	0.6	38	1.6
WTCL	153	5.1	274	1.7

* This 'ball park' estimate does not make provision for the effects of inflation, interest or tax in the calculations.
** Results for more fully depreciated pipeline companies will be higher.

It should be noted that TQM's unit cost estimates were substantially higher than those of the other two companies for similar work. Presumably this anomaly would be addressed prior to Board approval. Westcoast's unit cost estimates for compressor station removal were also quite high. However, their high negative salvage relative to cost of service shown in Table 4.4.2 is to be expected as a result of their three large processing plants.

Nevertheless, these tables demonstrate that the funds to be collected by negative salvage are potentially a very minor component of cost of service at this time (particularly if alternatives to straight line recovery are employed, see section 5.4).

Chapter 5
Financial Aspects

5.1 Accounting Profession's View of Negative Salvage

The Canadian Institute of Chartered Accountants (CICA) Handbook does not contain any specific directives on negative salvage. However, accountants accept the principle of recognizing salvage in depreciation accounting. To date, negative salvage has not presented any problems in industrial accounting as costs of abandonment have not been significant and were classified as period costs, when incurred.

If negative salvage is not provided for, either through depreciation or by other funding methods, then the loss resulting from negative salvage would be classified as an extraordinary item on the income statement. Section 3480 of the CICA handbook reads as follows:

"Extraordinary items should include only gains, losses and provisions for losses which, by their nature, are not typical of the normal business activities of the enterprise, are not expected to occur regularly over a period of years and are not considered as recurring factors in any evaluation of the ordinary operations of the enterprise." An example given of an extraordinary item was - "the discontinuance of, or substantial change in, a business programme or policy such as sale or abandonment of a plant or significant segment of the enterprise or sale of investments not acquired for resale."

5.2 Current Procedures for Negative Salvage under Uniform Accounting Regulations

The Board has had a rather limited exposure to abandonments that involve negative salvage. To date, the Board has not adopted a set uniform policy for dealing with negative salvage costs. Rather the Board has decided the appropriate course of action based on the individual circumstances of each case. Recent decisions by the Board, on applications by Trans Mountain and Interprovincial, to recover losses resulting from negative salvage that were not provided for during the service life of the plant, provide insight into the range of regulatory treatments that the Board has deemed to be appropriate in the past.

In the case of Trans Mountain, the Company took 11 pump stations out of service in 1978 but continued to maintain them until 1983. In 1983 the stations were dismantled, removed and salvaged for an approximate net cost of $540,000. The Board ordered that the abandonment be treated as an extraordinary retirement and the net salvage value was charged to account 171 (Extraordinary Plant Losses). The extraordinary loss was recovered by amortization over a two-year period to cost of service and the unamortized amounts were included in rate base.

In the case of Interprovincial, the Company replaced 45.7 miles of pipeline near Edmonton in 1980 and classified the retirement as ordinary retirement. The pipe had been in service for a relatively short period of ten or eleven years. Dismantling costs were $648,700 and proceeds from salvage were $147,400. The loss on retirement was $2,582,664 (including $2,081,364 undepreciated balance of retired pipe). The Board ruled that the retirement was an extraordinary retirement; allowed the Company to amortize the loss over a five-year period; and excluded the average unamortized loss balance from rate base.

Under the Board's Uniform Accounting Regulations, neither a gain nor a loss on an ordinary retirment of a utility asset is recognized in the year. When a pipeline asset is taken out of service both the asset account and the accumulated depreciation account are reduced by the original cost. Therefore, a loss on an ordinary retirement remains in the rate base. Any proceeds received on disposal of the asset are added to the accumulated depreciation account thus reducing rate base. On an extraordinary retirement, the loss would be transferred from accumulated depreciation to the extraordinary plant losses account, and the Board would determine or approve the disposition of the loss.

It appears that during the development of the depreciation sections of the Board's Uniform Accounting Regulations, which emanated from the accounting regulations for railroads, an assumption may have been made that salvage proceeds would exceed costs of removal. However, the definitions for "net sal-

vage value" and "service value" do not preclude negative salvage. Appendix VI of this report contains specific definitions and sections from the Uniform Accounting Regulations that relate to net salvage value.

If negative salvage is provided for as a component of depreciation then the regulations as they are now written may suffice. If the provision for negative salvage is not provided for through depreciation, then amendments to the regulations may be required.

5.3 When Should the Collection of Funds for Negative Salvage Commence?

In recovering costs through utility rates, a basic regulatory and financial principle is that the customers who benefit from a required expenditure should bear the costs. In other words, there should be a fair allocation of costs among customer generations. Although regulators strive to attain this principle, the conflicting variables required to be accounted for in cost of service calculations tend to prevent its full achievement (see comments at 5.4.1 and 5.4.2).

This principle of matching costs to benefits has been brought out in a number of cases in the United States, predominantly regarding nuclear power plants but also some in the petroleum industry.[1]

As can be seen from these cases, the regulatory precedent is that current customers should pay for any benefits they receive rather than deferring the collection of funds until the facilities are near the end of their service life and hence only collecting from future ratepayers.

However, in order to determine whether the collection of funds could be deferred, three different cost recovery methods have been examined under three different scenarios. Figure 5.3 illustrates the effects of delaying collection of $10 million of negative salvage costs in current dollars. With annual inflation at five percent, this amount would grow up to $43.2 million in 30 years.

The Future Cost Net Negative Salvage Method (Method 1), involves estimating the total future decommissioning costs and dividing by the number of years from the current year to the last year of the plant's service life to arrive at the annual charge. In this example it is assumed that the funds would be maintained internally, within the Company. Instead of earning interest, the total of the funds collected would be deducted from rate base in calculating the company's cost of service. (If an annual 12 percent rate of return on rate base was assumed then the savings in the company's cost of service would exceed the annual negative salvage contributions required in the eighth year of collection.) Under this method, if we defer the collection of the annual charge for 10 years, the annual charge will increase 50 percent from $1.44 million/year to $2.16 million/year. Alternatively, if we defer the collection for 20 years, the annual charge will increase 200 percent from $1.44 million/year to $4.32 million/year.

The Sinking Fund with Equal Annual Charges Method (Method 2) involves collecting the same amount every year during the service life of the plant so that the accumulated annual charges plus the earned compound interest will equal the total decommissioning costs at the end of the plant's service life. Under this method, if we defer the collection of the annual charge for 10 years, the annual charge will increase 147 percent from $0.38 million/year to $0.94 million/year. Alternatively, if we defer collection for 20 years, the annual charge will increase 684 percent from $0.38 million/year to $2.98 million/year.

The Method of Changing Estimated Costs Annually (Method 3) involves updating the estimated decommissioning costs on a yearly basis so that the annual amount collected will vary each year as changes in costs and inflation are incorporated. Interest is compounded annually on the funds precollected under this method. Thus, if we defer the collection for 10 years, the annual charge will increase from $0.30 million to $0.36 million in year 11. If we defer collection for 20 years, the annual charge will increase from $0.93 million to $1.83 million in the 21st year. For other years refer to the graph.

As shown by the graphs, a deferral of 10 or 20 years will result in future ratepayers bearing a much greater increase in annual charge for either one of the straight-line methods (1 and 2) whereas for Method 3, the increased burden on future ratepayers will not be as pronounced. However, under method 3, the annual charge for future ratepayers will be much greater than it will be for the other two methods since its annual charge is increasing every year.

5.4 How Should Negative Salvage be Collected?

5.4.1 Straight Line

Although the straight line method is the most common method used for recording depreciation it does not

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1 Some particular cases dealing with this principle are:
- Alabama Public Service Commission re: Alabama Gas Corporation
- Connecticut Dept. of Public Utility Control re: Connecticut Light and Power
- New York Public Service Commission re: Consolidated Edison Company
- Maine Public Utilities Commission re: Maine Public Service Company

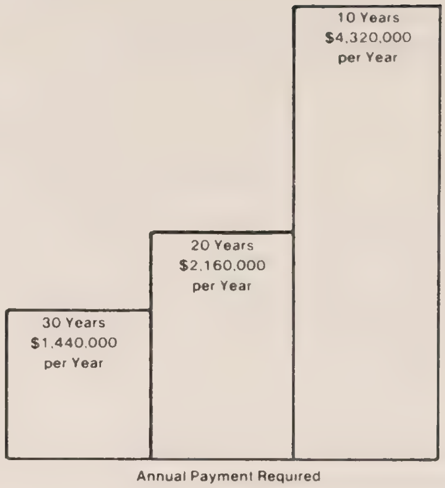
Figure 5.3

Change to Annual Payment if Funding Period Shortened

Method 1 Future Cost Method With Internal Reserve

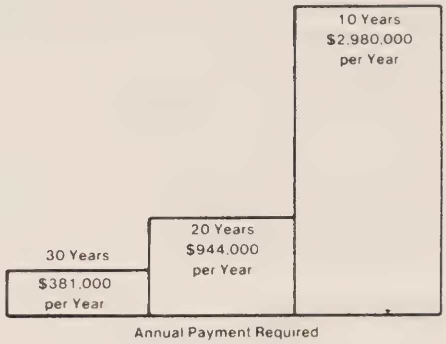
Assumes equal annual charges over the funding period to provide $10 million (1985 dollars) inflated at 5% per year for 30 years to $43.2 million.

The negative salvage funds collected would be deducted from rate base. No interest is paid on the funds provided, however, users benefit through a reduction in cost of service.



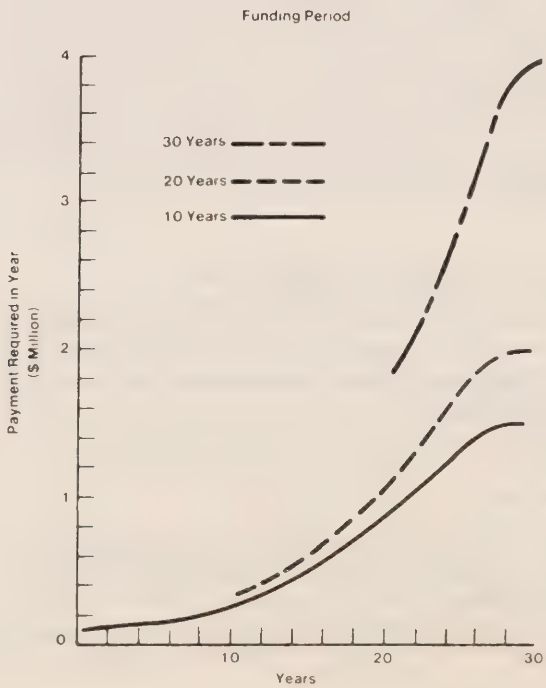
Method 2 Sinking Fund

Assumes equal annual charges over the funding period to provide $10 million (1985 dollars) inflated at 5% per year for 30 years to $43.2 million with interest earned on contributions compounding annually at 8%.



Method 3 Changing Cost Estimate Annually

Assumes changing annual charge each year to account for inflation as it occurs. To provide $10 million (1985 dollars) inflated at 5% per year for 30 years to $43.2 million with interest earned on contributions compounding at 8%.



follow that it is the most suitable method for providing for negative salvage. In fact, as it will be necessary to recalculate the required negative salvage provision from time to time to reflect the impact of inflation and changing technology, it is likely that the provision for negative salvage will change over time.

One of the main reasons for the popularity of the straight line depreciation method amongst utilities is the insistence by the financial community, that debt be repaid at a rate equal to, or greater than, the rate the assets being depreciated are actually used up in the production process. As no debt financing is involved in providing for negative salvage, the companies will not be restricted by the requirements of the financial community.

5.4.2 *Tariff Levelling Possibilities*

Existing tariffs providing for straight line depreciation are, to some extent, inequitable in that early users of a system pay the rate of return on the original cost of the rate base whereas later users obtain the advantage of paying the rate of return on a depreciated rate base. The later users also have the advantage of paying in cheaper dollars, if inflation continues. As an offset against these advantages, it may be argued that the later users could bear a larger share of providing for negative salvage revenues.

5.4.3 *Periodic Recalculation of Required Reserve*

Unlike traditional depreciation provisions where the amount to be depreciated is relatively fixed, a provision for negative salvage will be subject to fluctuations due to changes in inflation rates, decommissioning technology, estimated service life, regulatory requirements, interest rates and other unanticipated changes. It will, therefore, be necessary to periodically recalculate the provision for negative salvage to accommodate these changes.

5.4.4 *Alternatives to Straight Line*

In the alternatives that follow it should be kept in mind that the annual charge could be an annual annuity payment required to fund the estimated negative salvage requirement.

Alternative 1

Estimate, in advance, the total future negative salvage costs in inflated dollars and provide for this on a straight line basis. Annual amounts would fluctuate to some extent as the total estimate is periodically updated.

$$\text{Annual Charge} = \frac{\text{Remaining Future Dollar Costs to be Collected}}{\text{Remaining Years}}$$

The problem with this method is that it requires early users to pay for future inflation costs.

Alternative 2

Estimate decommissioning costs in current dollars and divide remaining balance to be collected by remaining years. Each year remaining costs may be increased by inflation.

$$\text{Annual Charge} = \frac{\text{Remaining Current Dollar Costs to be Collected}}{\text{Remaining Years}}$$

The problem with this method is that is shifts the burden of inflation to the later users and could result in excessively high charges in the last few years of service.

Alternative 3

The same as Alternative 2 plus a charge each year for the loss of purchasing power of the funds previously collected.

$$\text{Annual Charge} = (\text{Previous Year's Inflation Rate}) \times (\text{Accumulated Funds}) + \frac{\text{Remaining Current Dollar Costs}}{\text{Remaining Years}}$$

This method deals directly with inflation on an annual basis. Although the cost of adjusting the fund balance for inflation every year increases as the system gets older, this increasing charge counter-balances the decreasing return on rate base charge to late users of a pipeline system.

5.4.5 *Actual Expenses versus Authorized Negative Salvage Provision*

Through the process of adjusting the negative salvage charges periodicially to reflect changes in estimated costs due to changes in inflation, technology and estimates of service life, it is expected that reasonable cost estimates can be developed. Any discrepancy between the actual decommissioning costs and the authorized negative salvage provision should be minimal. The possibility of retaining any cost savings and the risk of having to absorb cost overruns would serve as an incentive to the Company to complete the work within budget.

5.5 Financial Management Options Available

5.5.1 Funding at Start Up

At start up of the facility, or as soon after as possible, cash or other liquid assets are deposited in a fund, to be managed by the Company, a trust or some other public body. The amount of the initial deposit is calculated by taking into account the estimated net salvage costs, predicted interest and inflation rates, taxes, and the remaining life of the asset. The funding costs are added to the rate base and amortized over the life of the pipeline.

The method provides a high degree of assurance that funds will be available for decommissioning. However, errors in predicting interest and inflation rates may require additional funding at future dates. Funding at start up is the most costly funding alternative as rate payers must pay a rate of return on the unamortized cost of the prepayment. Some form of levelling would be required to ensure that early users do not pay more than their share of return on and amortization of the prepayment.

5.5.2 External Sinking Fund

An annual amount is set aside in an external fund such that the annual payments combined with the investment income earned would be sufficient to provide for the estimated negative salvage costs. The fund would be administered separately from the utility's assets, possibly by an independent manager or trust company.

This type of funding is less expensive than prepayment and still offers a high degree of assurance that the funds will be available when needed. Annual contributions can be changed, as suggested in section 5.4, to adjust for changes in estimated interest, inflation and negative salvage costs. Such funds would be non-accessible to creditors even if the operation should go out of business.

5.5.3 Internal Reserve

The net negative salvage costs are added to the original cost of the assets (but not rate base), to form the basis for depreciation. The cost is recovered through higher annual depreciation charges included in the cost of service. The funds collected are not held in a separate sinking fund but rather may be invested in utility assets against which bonds could be issued when the funds are required. As the rate base is reduced by the extra depreciation collected, the rate payers would receive a benefit in the form of a lower return on rate base.

This method is subject to the greatest risk as the Company might mismanage the funds. If the Company were to become insolvent, creditors might have a claim on these funds. An internal unfunded reserve of this nature shifts the greatest costs to the early users as they would pay the depreciation but receive less benefit than later users from the rate base reduction.

5.5.4 Industry Self Insurance

An industry-administered insurance fund could be established to collect premiums for decommissioning from all pipeline companies and pay all pipeline decommissioning costs. Premiums could be based on independently determined estimates of decommissioning costs for each company. If legitimate status as an insurance company could be established then reserves for future claims could, perhaps, eliminate any taxation problems on investment income thereby allowing faster fund growth rates and lower decommissioning premiums. The pooling of risks in such an insurance company could eliminate problems that might occur if a company's actual negative salvage costs exceeded the reserve funds provided.

The concept of an industry administered insurance company is just an idea, and no research has been done by Board staff to determine its feasibility.

5.5.5 Negative Salvage or Decommissioning Tax

Negative salvage costs may occur for many Canadian pipeline companies at a time when their activities are winding up. If sufficient funds were not available for decommissioning the financial burden might fall upon the taxpayer. This being the case we might consider a tax for decommissioning with the government assuming all eventual responsibility for the costs. This alternative might be practical if facilities are to be abandoned in place with perpetual maintenance.

5.6 Income Tax Implications

Recent applications made by pipeline companies under the Board's jurisdiction have indicated that the inclusion of negative salvage costs in the depreciable base of the utility would result in a higher depreciation charge collected in the cost of service.

5.6.1 Current Income Tax Provisions

Under the current income tax laws, revenues and expenses related to negative salvage would be treated as follows:

1. Depreciation charges on account of negative salvage, to the extent that they are collected before they are spent, are taxable in the year collected.
2. Income earned on funds pre-collected on account of negative salvage is taxable in the year earned.
3. Plant removal costs are deductible for income tax purposes in the year(s) those costs are actually incurred.

5.6.2 Impact on the Cost of Service

For toll purposes, the inclusion of negative salvage costs in the depreciable base of the utility would have the following effects on the cost of service:

1. On a normalized basis, the income tax component of the cost of service would not be affected due to the collection of depreciation on account of negative salvage in the cost of service. However, the deferred income taxes would be decreased by half the amount of depreciation so collected assuming a 50 percent tax rate[1].
2. On a flow-through basis, the income tax component of the cost of service would be increased by an amount equal to the depreciation collected on account of negative salvage assuming a 50 percent tax rate. When the negative salvage costs are actually incurred and deducted for income tax purposes, the income tax provision would be decreased by an amount equal to the income tax deduction assuming a 50 percent tax rate. However, theoretically there would be no ratepayers to receive these benefits at the time that the negative salvage costs are actually incurred[1].
3. Income earned on funds precollected on account of negative salvage is considered non-utility income, and consequently such income would have no impact on the cost of service.

5.6.3 Alternatives to Alleviate the Impact on the Cost of Service

In order to alleviate the income tax impact of negative salvage on the cost of service, the following alternative arrangements may be considered:

1. In Westcoast's recent Hearing (RH-5-83), the Company proposed the following procedures:
   i) Negative salvage amounts would be collected on account of services to be rendered to the ratepayers. Reserves respecting the services to be rendered would offset the amount included in income currently. When the negative salvage costs are actually incurred, the accumulated reserves brought into income at that time would be offset by these actual costs which are deductible for tax purposes. A review of that proposal indicated that negative salvage collections might not be considered by Revenue Canada as payment on account of services to be rendered, and consequently, the offsetting reserve(s) would not apply.
   ii) Negative salvage amounts would be remitted to a trust fund as capital contributions to the fund and thus would not be taxable at the time of remittance. The investment income earned on the negative salvage amounts so remitted would be taxed in the trust. When the Company withdraws the funds (capital contributions plus net investment income) from the trust to finance the removal costs, the withdrawals would be included in the Company's income and offset by the income tax deductions in respect of the actual negative salvage costs incurred at that time. A review of that proposal indicated that the Company may be able to obtain a favourable income tax advance ruling in respect of that arrangement.
2. Informal discussions with speciality rulings officers of Revenue Canada Taxation have identified the following alternatives which would require changes in the existing laws:
   i) The creation of a tax-exempt government organization to handle the negative salvage funds would alleviate any income tax impact on the cost of service.
   ii) The creation of a prescribed income tax reserve in respect of negative salvage collections similar to those in paragraph 20(1)(o) and subsection 26(2) of the Income Tax Act would be supportive of Westcoast's proposal discussed under alternative 1.i) above.
   iii) The creation of a tax levied by the government to finance the costs of plant removal for all pipelines when the obligation to do so materializes. This would alleviate any

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1. For simplicity, the impact on the rate base, and consequently on the return on equity and the income tax provision, arising from the deduction of accumulated depreciation and deferred income tax credits in the calculation of the rate base has been ignored in this analysis. This impact on the income tax provision would be downwards and relatively immaterial

income tax impact on the cost of service. However, the NEB Regulations would have to be changed so that the responsibility for removing the plant would be shifted from the utilities to the government.

3. A regulatory alternative could be the exclusion of the depreciation charges precollected on account of future negative salvage costs from all related items in the calculations of the income tax component of the cost of service. In this case, the income tax payable on the precollected negative salvage costs will be borne by the utility which will also receive the income tax benefits when it removes its plant and actually incurs the negative salvage costs. In theory, there would be no ratepayers to receive these income tax benefits at that time.

Appendix I

U.S. Precedents re Negative Salvage

1. Alabama Public Service Commission
- re Alabama Gas Corporation
(v. 43, Public Utilities Reports, 4th Series (43 PUR 4th), p. 710; Alabama Gas Corp. Docket No. 18046, July 2, 1981)

The Commission ruled that prospective negative salvage should not be considered in determining accrued depreciation because it does not represent a part of original cost. However, the Commission did not dispute the fact that negative salvage is a proper element of utility cost, but it would not allow the company to collect the cost of negative salvage until it is incurred. An appeal by Alabama Gas Corporation to the Supreme Court of Alabama was heard during the October term 1982-1983, and the Court held that a fundamental objective in utility ratemaking is that customers who benefit from a service should bear the costs of providing that service. "To recognize net salvage (positive or negative) only when it is actually experienced instead of distributing the amounts over the service life of the related property violates this basic principle." However, the Court's resolution beyond this point is vague.

2. Colorado Public Utilities Commission
- re Public Service Company of Colorado
(41 PUR 4th, p. 225 ff; Docket No. 1425, Decision No. C80-2346, December 12, 1980)

The Commission allowed negative salvage in depreciation rates but ordered that provision for negative salvage recovered through rates be segregated in a funded reserve to be controlled by an independent trustee. The particularized methodology of how Public Service Co. shall do this shall be up to the company, subject to the approval of the Commission.

3. New York Public Service Commission
- re Rochester Gas and Electric Corporation
(38 PUR 4th, pp. 143, 154-5; Cases 27606 et al. Opinion No. 80-28, July 18, 1980)

The Commission allowed accrual of revenues for negative salvage and did not require a segregated fund. The reserve fund method was held to be more costly than the accrual method which was expected to provide the public adequate protection. The nuclear plant decommissioning expense allowance which was approved uses a 29-year accrual schedule with the present value of future decommissioning costs discounted at a 5 per cent annual rate.

4. Connecticut Department of Public Utility Control
- re Connecticut Light and Power Company
(41 PUR 4th, pp. 1, 57-59; Docket No. 800403, October 9, 1980; Supplemental Decision, October 17, 1980)

Allowed to include negative salvage in depreciation. The ultimate cost of decommissioning nuclear generating facilities should be borne by customers who benefit from them.

5. Federal Energy Regulatory Commission
- re Connecticut Light & Power (case No. ER 76-320), and
- re Connecticut Yankee Atomic Power (case No. ER 78-360) (Reported in Inside F.E.R.C., November 24, 1980)

The Commission for the first time decided to allow electric utilities to begin collecting from current ratepayers the cost of eventually decommissioning nuclear generating units. After struggling with the issue for several months, the Commission in cases involving Connecticut Light & Power and Connecticut Yankee Atomic Power authorized the companies to include negative salvage value in their current rates to reflect the cost of putting the nuclear units out of service. The Commission used the cost of mothballing the plants in developing the appropriate negative salvage values.

The struggle over decommissioning centred on methods considered by the Commission for decommissioning plants, with administrative law judges (ALJs) and staff supporting relatively low-cost mothballing while the companies favoured more costly partial entombment of the nuclear facilities. The Commission accepted opinions of ALJs and staff that it was best to accept the "most conservative approach" (the

least expensive method). The Commission also echoed the ALJs and staff in assuring utilities that the negative salvage value can always be adjusted in future rate cases to cover any increased costs of decommissioning.

The Commission adopted ALJ Benkin's conclusion in the Connecticut Yankee Atomic case that the company should not be required to establish a separate escrow account for negative salvage revenues. The Commission added that its decision in the pending cases does not preclude it from requiring separate accounts in future decommissioning cases.

6. **Connecticut Division of Public Utility Control - re Connecticut Natural Gas Corporation**
   (37 PUR 4th, pp. 287, 302, 303; Docket No. 791202, June 25, 1980)

The net negative salvage value of distribution and transmission mains and services was increased to reflect the effect of recent federal regulations on main retirement.

7. **New York Public Service Commission - re Consolidated Edison Company of New York, Inc.**
   (29 PUR 4th, pp. 327, 332-335; Case 27353, Opinion No. 79, April 6, 1979)

An important statement made by the Commission in this case was:
"We should allow some revenue to meet decommissioning expense because it is a legitimate cost of service which should be paid by those customers using the nuclear plant. Decommissioning is a necessary expense associated with an investment that no party contends is imprudent or unjustified. Under these circumstances, the most equitable choice is to allow the utility to recover the cost from customers. Moreover, the company should begin to provide for these costs now, collecting them from the customers deriving benefit from the plant rather than from those who are taking service at the time the plant is decommissioned."

The Commission considered the cost of mothballing and later dismantling (which had been advocated by a judge) as being more expensive than immediate dismantling of a nuclear plant at the end of its service life. The Commission calculated the decommissioning allowance on the basis of immediate dismantling, but it stated that it can readily change this allowance in response to changed technological, environmental and other conditions.

The company advocated accumulation of funds for decommissioning expense through direct charges to current customers on the basis of an ordinary annuity formula, segregation of the funds collected, and investment of them in securities. The method that their staff employed incorporated depreciation with annual accruals. The funds collected could be invested in other Con Edison utility plant; therefore, the accumulated amount of these funds would be deducted from the rate base. All agreed that the segregated fund proposal was more expensive to consumers.

The Commission held that the less costly alternative will provide adequate protection for the company and the public. Furthermore, the Commission implemented a judge's suggestion, to which Con Edison acquiesced, to have the magnitude of the decommissioning allowance increase over time. This will prevent inflation from reducing the burden on future customers at the expense of existing customers. After further, detailed explanations, the Commission decided that a constant decommissioning charge be used in the first few years, and a graduated charge, based upon a 5 per cent inflation rate, in the remaining years.

8. **New York Public Service Commission - re Consolidated Edison Company of New York, Inc.**
   (35 PUR 4th, p. 643; Case 27544, Opinion No. 80-8, March 7, 1980

The Commission permitted a 40 per cent negative salvage rate for a gas utility's Mains.

9. **Indiana Public Service Commission - re Indiana and Michigan Electric Company**
   (52 PUR 4th, pp. 340-348; Cause No. 36760-S1, March 23, 1983)

The Commission found that it was not possible currently to determine an annual provision for nuclear plant decommissioning expense that would be for all times appropriate, since seemingly minimal variances in actual inflation or net rates of return could, over the period of collection, materially change the amount of the annual provision necessary to assure that adequate funds were available when needed. The Commission adopted as the annual provision for decommissioning expense an amount found reasonable and appropriate under the evidence presented and in view of the ongoing review and revision procedure that it instituted.

The annual nuclear plant decommissioning expense provision authorized by the Commission carried with it the collection of the cost of decommissioning associated with earlier periods of the operation of the

company's plant to recognize that failure to provide for recovery associated with prior periods might defeat the purpose of recognizing future decommissioning costs, i.e., to assure the availability of sufficient funds for the purpose of decommissioning the plant at the end of its useful life.

The Commission instituted a procedure whereby the annual nuclear plant decommissioning expense provision would be reviewed as an element of cost of service in each of the company's subsequent rate cases, finding that such a time period would be long enough to provide a basis for intelligent adjustment while not unduly prolonging any unfair impact on ratepayers. If three years elapsed between rate cases, the company would then file a separate review and report on the adequacy of the then existing annual provision.

The Commission determined that the company's annual provision relating to nuclear plant decommissioning costs should be accumulated in an external trust fund devoted to holding and investing the decommissioning funds. The company should enter into a trust agreement that (1) recognized the limited purpose for which the funds could be used, (2) provided reasonable safeguards as to the nature of the investments in which such funds might be made by the trustee, and (3) reflected that the trustee should make no investments in securities issued by the company or any of its affiliates.

This paragraph is not strictly dealing with decommissioning of a nuclear facility, but it is probably of sufficient interest so that it should be added here: Pursuant to the requirements of the Nuclear Waste Policy Act of 1982, which created a nuclear waste fund for the disposal of spent nuclear fuel consisting of fees by the nuclear utilities, the Commission directed the company to include in its estimated costs incorporated in the fuel cost adjustment proceedings the charge of one mill per kilowatt-hour for electricity generated at its nuclear facility and sold on or after 7 April 1983 (the date established by the Act).

10. Florida Public Service Commission - re Decommissioning Costs of Nuclear Power Generators

(47 PUR 4th, pp. 357-362; Docket No. 810100-EU(CI), Order No. 10987, July 3, 1982)

The following is a summary of a discussion by the Commission of proper accounting and rate-making methods for decommissioning costs.

Nuclear power plants - Decommissioning methods

According to Nuclear Regulatory Commission policy and the general regulatory atmosphere, only immediate or delayed dismantlement appeared to the Commission to be acceptable nuclear power plant decommissioning methods.

Power plant decommissioning expense

The Commission held that a current accounting treatment of costs associated with nuclear power plant decommissioning, by including it as part of the depreciation expense pertaining to the plants, was insufficient to monitor properly the expense being charged to customers.

Segregation of expenses - Accumulated fund

A better approach to accounting for decommissioning costs would be to segregate the portion of the accumulated provision from the depreciation rate.

Accounting - Accumulated depreciation reserve - Exclusion from rate base

The Commission continued the practice of subtracting the accumulated decommissioning reserve from rate base, resulting in a lower current revenue requirement to the ratepayer.

Apportionment - Decommissioning costs - Allocation between present and future customers

An internally funded reserve was the appropriate method to account for decommissioning costs since the proper allocation of the costs of decommissioning should be between present and future customers.

Accounting - Decommissioning costs - Funding methods

Discussion of four funding methods currently available to utilities to pay for the costs of decommissioning nuclear power plants:

1. *Prepayment* at the time of initial plant operation based on estimated future costs;
2. An *internally funded reserve* which restricts usage of the funds;
3. An *externally funded reserve*, through the use of a trust or other fund; and
4. An *internally unfunded reserve* which allows the company to use the funds for general corporate purposes.

11. Illinois Commerce Commission - re Commonwealth Edison Company

(35 PUR 4th, pp. 49, 50, 71-73; No. 79-0214, February 6, 1980)

The Commission required the company to set up an account to accumulate amounts collected from ratepayers to provide for the cleaning and decommissioning of nuclear power plants

12. **The Public Utilities Commission of Ohio**
- re The Dayton Power and Light Company (DP & L)
(Case No. 79-372-GA-AIR; Opinion and Order, May 7, 1980)

The company applied for an increase in the rates to be charged for gas service. The Commission allowed negative salvage values for mains, measuring and regulating station equipment, and other fixed assets at various rates. In part, these negative salvage rates were based on statewide averages rather than on the limited retirement experience of DP&L.

13. **Massachusetts Department of Public Utilities**
- re Western Massachusetts Electric Company
(37 PUR 4th, pp. 219, 220, 227-229; D.P.U. 20279, May 30, 1980)

Estimated future nuclear plant decommissioning expenses were allowed for ratemaking purposes only to the extent that such costs were reasonably certain to occur. A contingency factor was not permitted to be considered in arriving at a reasonable ratemaking allowance for future nuclear plant decommissioning expenses. A ratemaking allowance for future nuclear plant decommissioning expenses was computed using a partial dismantlement/delayed removal method with a 30-year dormancy period and local property tax escalations excluded.

14. **Oregon Public Utility Commissioner**
- re Portland General Electric Co.
(37 PUR 4th, p. 656; UF 3592, Order No. 80-612, August 18, 1980)

The commissioner authorized the company to adopt a sinking fund method to account for the estimated cost of decommissioning its nuclear power plant and the cost of permanent storage of nuclear fuel waste.

15. **Maine Public Utilities Commission**
- re Central Maine Power Co.
(38 PUR 4th, p. 573; Docket Nos. 80-25, 80-66, October 31, 1980)

The Commission approved the decommissioning fund for the company's nuclear power plant and approved the company's request for a 25 percent contingency allowance.

16. **Maine Public Utilities Commission**
- re Maine Public Service Company
(44 PUR 4th, pp. 104-106; Docket No. 80-180, June 1, 1981)

The company was permitted to include as a current expense its estimated annual cost associated with the future decommissioning of a nuclear generating station for, although the expense had not been incurred and would not be known until decommissioning was concluded, the Commission believed that those costs, being reasonably associated with the provision of service, should not be underwritten by ratepayers taking service after the plant's usefulness had expired.

17. **Iowa State Commerce Commission**
- re Peoples Natural Gas Company
(44 PUR 4th, pp. 62, 63, 75, 76; Docket No. RPU-79-30, August 14, 1981)

A net negative salvage rate should be applied to the gas distribution utility's principal plant accounts where it can be shown that the cost of removal exceeds the value of the asset removed.

18. **Wisconsin PSC Approves Accounting Method**
for Nuclear Plant Decommissioning Costs
(NARUC No. 2-1983, January 10, 1983, p. 12)

The Public Service Commission of Wisconsin has approved a straight line negative salvage method to provide funds for nuclear power plant decommissioning. The necessary funds would be invested internally by the utilities to meet decommissioning costs at the end of a nuclear plant's life as well as for premature decommissioning after five years.

Three nuclear power plants in Wisconsin are covered by the new rules, two reactors at Point Beach and one at Kewaunee. The Point Beach plants are owned by Wisconsin Electric Power Company, and the Kewaunee plant is owned jointly by Wisconsin Public Service Corporation, Madison Gas and Electric Company, and Wisconsin Power and Light Company.

The accounting method approved by the Commission is the same as that currently in use by the utilities except that decommissioning costs are expressed in terms of future dollars estimated at the time of decommissioning. Under this method the depreciation reserve is accumulated in equal annual increments over the service life of the plant.

No insurance against premature or unexpectedly costly decommissioning exists at this time. However, the Public Service Commission has ordered the operating owners of the Wisconsin nuclear plants to seek proposals and bids for this insurance within the next 18 months.

19. **California Public Utilities Commission**
- re Nuclear Facility Decommissioning Costs
(52 PUR 4th, pp. 618-643, Decision No. 83-04-013, OII 86, April 6, 1983)

The following is a summary of a Commission discussion and selection of methods of financing nuclear plant decommissioning costs.

Financing - Criteria

In assessing the various alternatives for financing decommissioning costs, the four criteria that the Commission used were: (1) assurance of availability of funds; (2) cost to ratepayers; (3) flexibility; and (4) equity to ratepayers.

External Sinking Fund

The mechanism that best satisfied the four criteria for financing nuclear decommissioning costs was an externally funded sinking fund managed by a third-party trustee.

Financing

Cost as a criterion of selecting a decommissioning method was held to be of minor concern where none of the alternative financing mechanisms would have added as much as one per cent to ratepayers' total electric utility bills.

Financing Mechanism - Periodic Reevaluation

In order that the adopted decommissioning financing mechanism be "flexible", the Commission will reevaluate the annual assessment for decommissioning in each operating utility's general rate case.

Tax Considerations

To spread equitably the costs of decommissioning over time, and to avoid a "windfall" tax write-off at the time of decommissioning, the Commission directed utilities to design their funds in anticipation that tax-exempt treatment would ultimately be obtained.

Financing Methods - External Fund

An external sinking-fund mechanism was adopted as the proper decommissioning finance method based on the four criteria of assurance, cost, flexibility, and equity.

Appendix II

Pertinent Sections of the NEB Pipeline Regulations

1. Oil Pipeline Regulations

Abandonment and Deactivation

119. A company that proposes to take a pipeline or any part thereof out of service for a period of twelve months or more shall apply to the Board for approval to deactivate such pipeline or part thereof for such period.

120. A company shall remove all abandoned pipeline facilities unless the Board has granted permission to leave such pipeline facilities in place.

121. A company abandoning or deactivating a pipeline or any part thereof shall take measures to protect the public, company personnel and the environment and shall

(a) disconnect all facilities to be abandoned or deactivated from any pipeline facilities that continue to operate;

(b) seal-off abandoned or deactivated parts of the piping by such means as blind flanges, blanks or weld caps;

(c) fill the piping with a medium approved by the Board, which, if inert gas, shall be maintained at a gauge pressure between 30 and 150 kilopascals;

(d) clean out storage tanks and purge them of hazardous vapours;

(e) maintain accurate records of the location of all buried piping and other facilities until they are removed;

(f) maintain warning signs and fences on pipeline facilities that have been abandoned but have not been removed; and

(g) maintain cathodic protection when requested by the Board.

122. A pipeline facility that has been deactivated for a period of twelve months or more shall not be reconnected or reactivated before

(a) the Board has approved the reconnection or reactivation; and

(b) the facility has been retested in accordance with these Regulations.

123. When a company ceases to be the owner of its pipeline right-of-way or is no longer responsible for the land tenure of its pipeline right-of-way, it shall, as soon as possible thereafter, remove its abandoned pipeline from the right-of-way unless the Board has granted the company permission to leave the abandoned pipeline in place.

124. A company that abandons a pipeline is responsible for that pipeline until such time as it is removed.

125. A company shall return a right-of-way from which a pipeline has been removed to a condition satisfactory to the Board.

2. Gas Pipeline Regulations

Inactivation and Abandonment

84. (1) A company that owns its pipeline right-of-way or is responsible for the land tenure of its pipeline right-of-way shall, in the specifications established by it under subsection 65(1), provide for the inactivation of its pipeline.

(2) A company referred to in subsection (1) shall

(a) physically disconnect from the remainder of its pipeline system all dormant pipeline facilities that have been shut down for a period of 12 months of more;

(b) seal, cap and fill with nitrogen or other inert gas under pressure all open ends of dormant facilities; and

(c) take and record periodic pressure readings of sealed and capped dormant facilities.

(3) A pipeline facility that has been dormant for a period of 12 months or more shall not be reconnected or put back into use by the company unless

(a) the Board has approved the reconnection or use; and

(b) the facility has been retested in accordance with these Regulations.

(4) When a company ceases to be the owner of its pipeline right-of-way or is no longer responsible for the land tenure of its pipeline right-of-way, it shall, as soon as possible thereafter, remove its abandoned pipeline from the right-of-way unless the Board has granted the company permission to leave the abandoned pipeline in place.

3. Proposed Onshore Pipeline Regulations 16 April 1985

Abandonment and Deactivation

91. A company that proposes to take a pipeline or any portion thereof out of service for a period of twelve months or more shall apply to the Board for approval thereof.

92. A company shall remove all abandoned pipeline facilities unless the Board is satisfied that for engineering, financial or environmental considerations it would be preferable to leave such pipeline facilities in place.

93. Where the Board has granted permission to leave the abandoned facilities in place, the company shall take measures to protect the public, company personnel and the environment and shall

(a) disconnect all facilities to be abandoned or deactivated from any pipeline facilities that continue to operate;

(b) seal off abandoned or deactivated parts of the piping by such means as blind flanges, blanks or weld caps;

(c) clean out storage tanks and purge them of hazardous vapours;

(d) maintain accurate records of the location of all buried piping and other facilities until they are removed;

(e) maintain warning signs and fences on pipeline facilities that have been abandoned but have not been removed; and

(f) maintain cathodic protection, unless otherwise authorized by the Board.

94. A pipeline facility that has been deactivated for a period of twelve months or more shall not be reconnected or reactivated before

(a) the Board has approved the reconnection or reactivation; and

(b) the facility has been retested in accordance with these Regulations.

95. A company that abandons a pipeline is responsible for that pipeline until such time as it is removed.

96. A right-of-way from which a pipeline has been removed shall be restored to its original condition or to a condition satisfactory to the Board.

4. Proposed Offshore Pipeline Regulations - 17 Dec 1984 Draft

Abandonment and Deactivation

99. A company that proposes to take a pipeline or any part thereof out of service for a period of twelve months or more shall apply to the Board for approval to deactivate such pipeline or part thereof for such period.

100. A company shall remove all abandoned pipeline facilities unless the Board is satisfied that for engineering, financial or environmental considerations, it would be preferable to leave such pipeline facilities in place.

101. Where the Board has granted approval to deactivate or abandon a pipeline or any part thereof, the company shall take measures to protect the public, company personnel and the environment and shall

(a) disconnect all facilities to be abandoned or deactivated from any pipeline facilities that will continue to operate;

(b) seal off abandoned or deactivated parts of the piping by such means as blind flanges, blanks or weld caps;

(c) fill the piping with an approved medium which, if inert gas, shall be maintained at a gauge pressure between 30 and 150 kilopascals;

(d) maintain accurate records of the location of all piping and other facilities until they are removed; and

(e) maintain corrosion control, unless otherwise authorized by the Board.

102. A pipeline facility that has been deactivated for a period of twelve months or more shall not be reconnected or reactivated before

(a) the Board has approved the reconnection or reactivation; and

(b) the facility has been retested in accordance with these Regulations.

103. A company that abandons a pipeline is responsible for that pipeline until such time at it is removed.

Appendix III

Buried Pipelines Under NEB Jurisdiction

Company	Diameter (mm)	Length (km)	Fluid Transported	To	From	Maximum Age on 1-1-85 (Approximate)
Alberta Natural Gas Company	914.	176	gas	U S. Border at Kingsgate, B.C.	Crowsnest, Alta.	23 yrs
Amoco Canada Petroleum Company Ltd.	60.3 to 457.	23	gas	WTCL Pipeline	Beaver Ridge, Yukon	13 yrs.
Aurora Pipe Line Co.	219.	0.8	crude oil	U.S. Border	Alberta	24 yrs.
	323.9	0.8	condensate & NGL			18 yrs.
Canadian-Montana Pipeline Co.	406.4	29.6	gas	U.S. Border	Alberta	25 yrs.
	406.4	6.3	gas	U.S. Border	Alberta	26 yrs.
	114.3	1.4	gas	U.S. Border	Alberta	6 yrs.
Champion Pipe Line Corp. Ltd.	219.1	97.	gas	Noranda, Qué.	Earlton, Ont.	20 yrs.
	219.1	1.9	gas	Temiscaming, Qué.	Thorne, Ont.	5 yrs.
Cochin Pipeline Company	323.9	982	propane, butane	U.S. Border at Alameda, Sask.	Fort Saskatchewan, Alta.	6 yrs.
	323.9	136	ethane, ethylene	Sarnia, Ont.	U.S. Border at Windsor, Ont.	
	273.1	7.4				
Consolidated Pipe Lines Co.	406.4	218.	gas	Herbert, Sask.	U.S./Sask. Border	13 yrs.
Dome-Kerrobert Pipeline Ltd.	273.1	154	NGL	Kerrobert, Sask.	Empress, Alta.	15 yrs.
Dome NGL Pipeline Ltd.	273.1	138	NGL	U.S. Border at Windsor, Ont.	Sarnia Pump Stn.	11 yrs
	219.1	12	NGL	Sarnia Pump Stn.	U.S. Border at Sarnia, Ont.	
Dome NGL/ Amoco Canada	219.1	11.85	Condensate	U.S. Border at Sarnia, Ont.	Sarnia Fractionation Plant	15 yrs
	219.1	11.3	LPG	U.S. Border at Sarnia, Ont	Sarnia Fractionation Plant	
	168.3	8.5	Condensate	Lateral to the Petrosar Plant		
Dome Petroleum Ltd.	219.1	3.2	ethane	Burstall, Sask	Empress, Alta.	14 yrs
Esso Resources Canada Ltd.	273.1	11.3	crude oil	Trans Prairie Pipeline (B.C.)	Boundary Lake field, (Alta.)	15 yrs
Foothills	914	855	gas	Kingsgate, B.C	Caroline, Alta	3 yrs
	1067	637	gas	Monchy, Sask	Caroline, Alta	
ICG Transmission Holdings Ltd.	114 to 323	190	gas	Fort Frances, Ont	Manitoba (TCPL) via the U.S	15 yrs

Buried Pipelines Under NEB Jurisdiction

Company	Diameter (mm)	Length (km)	Fluid Transported	To	From	Maximum Age on 1-1-85 (Approximate)
Interprovincial Pipe Line Ltd	400	1182	refined products and NGL	Gretna, Man.	Edmonton, Alta	34 yrs
	450	1182	crude oil	Gretna, Man.	Edmonton, Alta.	34 yrs
	500	1182	crude oil	Gretna, Man	Edmonton, Alta	34 yrs
	400	50	crude oil	Edmonton, Alta	Redwater	34 yrs
	600	216	crude oil	Gretna, Man.	Regina, Sask.	31 yrs
	500	251	crude oil	Toronto, Ont.	Sarnia, Ont.	27 yrs.
	600	132	crude oil	Regina, Sask.	Edmonton, Alta.	26 yrs.
	300	148	crude oil	Fort Erie, Ont.	Sarnia, Ont	21 yrs
	850	541	crude oil	Misc. Looping	Misc. Looping	18 yrs.
	500	148	crude oil	Fort Erie, Ont.	Sarnia, Ont.	12 yrs
	1200	160	crude oil	Gretna (Loop), Man.	Edmonton, Alta	12 yrs
	750	821	crude oil	Montreal, Que.	Sarnia, Ont.	8 yrs.
	400	42	crude oil	Nanticoke, Ont	Mt. Hope, Ont.	7 yrs.
Interprovincial Pipe Line (NW) Ltd.	323 9	868	crude oil	Zama, Alta	Norman Wells, NWT	0 yrs.
Manito Pipelines Ltd.	273.1	184	crude oil and condensate	Kerrobert, Sask	Blackfoot, Alta.	8 yrs.
	168.3	184				
	114.3	184				
Many Islands Pipe Lines (Canada) Ltd.	406.4	65	gas	Unity, Sask.	Nova, (Alta.)	19 yrs
	219 1	31.5	gas	Smiley, Sask	Esther, Alta.	7 yrs.
	273.1	28.3	gas	Beacon Hill, Sask.	Cold Lake, Alta.	7 yrs.
Mid-Continent Pipelines Ltd.	406.4	1.36	gas	Sask.	Alta.	
	610	1.36	gas			22 yrs.
Minell Pipeline Ltd.	168.3	69.7	gas	Russell, Man.	Sask.	20 yrs.
Montreal Pipe Line Limited	323.9	113.2	line deactivated	Montreal, Que.	U.S. Border at Highwater, Que.	44 yrs
	457	113.2	crude oil			35 yrs
	610	113.2	crude oil			20 yrs
Mont Resources Ltd.	50 8	0 2	crude oil	U.S. Border	Alberta	25 yrs.
Murphy Oil Company Ltd.	88.9	0.76	crude oil	U.S. Border	Red Coulee, Alta.	19 yrs.
	88.9	0 76	inactive			
	168 3	18	crude oil	U.S. Border	Milk River, Alta.	17 yrs.
Niagara Gas Transmission Ltd	323 9	14.4	gas	U.S. Border	St. Andrew, Ont.	25 yrs
	406 4	0 83	gas	Pointe Gatineau, Qué.	Rockliffe, Ont.	29 yrs.
	305	0.31	gas	Ottawa, Ont.	Hull, Québec	26 yrs.
Northwest Transmission Co	114 3	1.6	crude oil	B.C. (Trans Prairie)	Alberta	16 yrs
Peace River Transmission Co	114.3	16	gas	Dawson Creek, B.C.	Alberta	25 yrs.
Petroleum Transmission Co	168	933	LPG	Winnipeg	Alberta/Sask.	20 yrs
Saskatchewan Power Corp.	219 1	18.5	gas	Alberta	Hoosier, Sask.	21 yrs.
Sun Pipe Line Company	219.1	3.57	crude oil	Sarnia, Ont.	U.S. Border	34 yrs

Buried Pipelines Under NEB Jurisdiction

Company	Diameter (mm)	Length (km)	Fluid Transported	To	From	Maximum Age on 1-1-85 (Approximate)
TransCanada PipeLines Ltd.	864 to 1219	4247	gas	Winnipeg, Man.	Sask. Border at Emerson, Alta	27 yrs
	762 to 914	163	gas	U.S. Border at Emerson, Man.	Winnipeg, Man	25 yrs
	273 to 324	21	gas	Sault Ste. Marie, Ont.	U.S Border at Sault Ste Marie, Ont.	17 yrs
	914	24	gas	Dawn, Ont.	U.S. Border at St. Clair, Ont.	18 yrs.
	762 to 1067	4174	gas	Toronto, Ont.	Winnipeg, Man.	27 yrs.
	168	40	gas	Thorne, Ont.	North Bay, Ont.	5 yrs
	914	428	gas	Morrisburg, Ont.	North Bay, Ont.	3 yrs.
	508 to 914	255	gas	U.S. Border at Niagara, Ont.	Toronto, Ont.	31 yrs.
	508 to 914	1015	gas	Montréal, Que.	Toronto, Ont	28 yrs.
	323 to 406	117	gas	Ottawa, Ont.	Morrisburg, Ont.	28 yrs.
	219 to 508	147	gas	U.S. Border at Philipsburg, Que.	St-Lazare, Que.	19 yrs.
Trans Mountain Pipe Line Co.	610	1250	crude oil	Vancouver, B.C.	Edmonton, Alta.	31 yrs.
	762	162		Loops		27 yrs
Trans-Northern Pipelines Inc.	273.1	616 2	refined products	Hamilton	Montreal	32 yrs
	323.9	21.27	refined products	Mirabel	St. Rose	12 yrs
	323.9	16 03	refined products	Dorval	St Rose	15 yrs.
	323.9	68 1	refined products	Ottawa	Farran's Pt.	21 yrs.
	406	58 9	refined products	Nanticoke	Hamilton	6 yrs
	406	16 82	refined products	Clarkson Jct.	Oakville	
	508	21.4	refined products	Tor. Airport Jct.	Clarkson Jct.	
	273.1	2.25	refined products	Clarkson	Lateral	
	273.1	2 79	refined products	Prescott	Lateral	
	273.1	18.3	refined products	Toronto	Lateral	
	219.1	5 3	refined products	Toronto Airport	Lateral	13 yrs
Trans Québec & Maritimes Pipeline Inc.	762	39	gas	Boisbriand, Qué.	St. Lazare, Qué	3 yrs
	610	254	gas	Québec, Qué.	Boisbriand, Qué.	2 yrs
Union Gas Ltd.	323.9	1 4	gas	Windsor, Ont.	U.S. Border	39 yrs.
Wascana Pipe Line Ltd	323.9	175	crude oil & condensate	U.S. Border	Regina, Sask.	13 yrs.
Westcoast Transmission Co Ltd	406 to 914	2331	sales gas	B.C./U.S. Border	Alta. & Northern B.C	27 yrs
	up to660	2104	raw gas	Misc. gathering lines in Northern B.C., Yukon & N.W.T.		
Westspur Pipe Line Company	323.9	177	crude oil & NGL	Cromer, Man.	Midale, Sask	30 yrs.
	406.4	121	crude oil	Cromer, Man.	Steelman, Sask.	29 yrs.
	219.1	8.4	inactive since 1981	U.S. Border	Pinto, Sask.	30 yrs.
Yukon Pipelines Ltd	114.3	145.6	refined products	Whitehorse, Yukon	White Pass, B.C.	43 yrs. installed above ground

Appendix IV

Above Ground Pipeline Facilities Under NEB Jurisdiction

Company	Meter Stations	Pump/Compressor Stations	Processing Plants	Other Facilities
Alberta Natural Gas Company	8	3		
Amoco Canada Petroleum Company Ltd.				
Canadian-Montana Pipeline Co.	3			
Champion Pipe Line Corp. Ltd.	4			
Cochin Pipeline Company		12		
Consolidated Pipe Lines Co.	1	1		
Dome-Kerrobert Pipeline Ltd.	1	1		1 Storage Facility
Dome-NGL Pipeline Ltd.	2	2		
Dome Petroleum Ltd	1			
Esso Resources Ltd.				1 Oil Separating & Treatment Facility
Foothills	2	3		
Interprovincial Pipe Line Ltd.		74		
Interprovincial Pipe Line (NW) Ltd.	1	3		
Many Islands Pipe Lines (Canada) Limited	2			
Minell Pipeline Ltd.	1			
Montreal Pipe Line Limited		2		1 Terminal Manifold
Niagara Gas Transmission Ltd.	3			
Peace River Transmission Co	1			

Above Ground Pipeline Facilities Under NEB Jurisdiction

Company	Meter Stations	Pump/Compressor Stations	Processing Plants	Other Facilities
Petroleum Transmission Co.		6		1 Storage Facility
TransCanada PipeLines Ltd	144	49		
Trans Mountain Pipe Line Co.		7		5 Storage Facilities
Trans-Northern Pipeline Inc	18	15		
Trans Québec & Maritimes Pipeline Inc.	10			
Union Gas Ltd.	1			
Wascana Pipe Line Ltd.		1		1 Terminal with Storage Facilities
Westcoast Transmission Co. Ltd.	75	31	4	
Westspur Pipe Line Company	4	3		3 Storage Facilities
Yukon Pipelines Ltd		1		2 Storage Facilities

Appendix V

Pertinent Sections of the Uniform Accounting Regulations

Definitions:

salvage value means the amount received, including insurance proceeds and including any amount received for material salvaged from plant retired where the material is sold.

net salvage value means salvage value minus any removal costs.

Pertinent sections:

36(1) Where a plant unit, whether replaced or not, is retired from pipeline operations, the book cost of the plant unit shall be credited to the appropriate plant account.

36(2) The book cost and the costs of removal of a depreciable plant unit retired and not replaced shall be debited to account 105 (accumulated depreciation - Gas Plant or Account 106).

36(3) The net salvage value of a plant unit retired shall be credited to the accumulated depreciation account.

Salvage Value

38(1) Where salvaged material is retained for use by a company, the original cost, estimated if not known, of the material, less a fair allowance for depreciation, shall be debited to account 150 (Plant Materials and Operating Supplies).

38(2) The salvage value of depreciable plant or salvaged material therefrom shall be credited to account 105 (Accumulated Depreciation - Gas Plant) or account 106 (Accumulated Amortization - Gas Plant), as applicable.

38(3) The removal costs incurred in dismantling or demolishing retired depreciable plant and in recovering salvage therefrom shall be debited to account 105 (Accumulated Depreciation - Gas Plant) or account 106 (Accumulated Amortization - Gas Plant), as applicable, except that the current cost of removing and replacing a minor item of plant in maintenance operations shall be included in the appropriate expense account.

Ordinary Retirement

39(1) In respect of depreciable plant, "ordinary retirement" means a retirement of depreciable plant that results from causes reasonably assumed to have been anticipated or contemplated in prior depreciation or amortization provisions.

39(2) There shall be no debit or credit to income or to retained earnings for an ordinary retirement.

Extraordinary Retirement

40(1) In respect of depreciable plant, "extraordinary retirement" means a retirement of depreciable plant that results from causes not reasonably assumed to have been anticipated or contemplated in prior depreciation or amortization provisions, including such causes as fire, storm, flood, premature obsolescence or unexpected and permanent shutdown of an entire operating assembly for reasons other than ordinary wear and tear.

40(2) Where the gain or loss on an extraordinary retirement is material, the company shall inform the Board and, unless otherwise directed by the Board, shall transfer the amount of the gain or loss from account 105 (Accumulated Depreciation - Gas Plant) or account 106 (Accumulated Amortization - Gas Plant) to account 331 (Extraordinary Income) or account 341 (Extraordinary Income Deductions), as applicable.

40(3) Notwithstanding subsection (2), a company may, with the approval of the Board, transfer all or part of the amount of a material gain or loss on an extraordinary retirement to 279 (Other Deferred Credits) or account 171 (Extraordinary Plant Losses), as applicable, for amortization at a rate approved by the Board.

40(4) Immaterial gains or losses resulting from extraordinary retirements shall be accounted for in the same way as ordinary retirements.

48 In sections 49 to 57:

"group system" means a system by which a weighted average rate of depreciation is calculated for a particular group of plant accounts, a plant account, or a group of assets within a

plant account, and established in recognition of the fact that some part of the investment in a group of assets may be recovered through salvage realization and that there will be variations in the service lives of the assets constituting the group, even among assets of the same class;

"service value" means the book cost of plant minus the estimated net salvage value of that plant.

49(1) Under the group system, in the case of an ordinary retirement of an individual asset in a group of assets, the accumulated depreciation attributable to the asset shall, for the purposes of these Regulations, be considered to be equal to the cost of the asset minus any amount that may reasonably be recovered through salvage realization, whether or not the actual service life of the asset is shorter or longer than the anticipated average service life for the group.

49(2) Assets, within a group of assets, remaining in use after reaching their average service life expectancy shall not be regarded as fully depreciated until actual retirement or until the group is fully depreciated, whichever is earlier.

52(1) There shall be debited each month to expenses or other appropriate accounts and credited to the accounts for accumulated depreciation amounts that will allocate, in a systematic and rational manner, the service value of the plant over its estimated service life.

54(2) The rates referred to in subsection (1) (depreciation rates filed) shall be based on the service value and the estimated life of the plant, as developed by a study of the company's history and experience and such engineering and other information as may be available with respect to future operating conditions.

Amortization

58 For the purposes of sections 59 and 60, "amortization" means the gradual recovery of an amount included in account 100 (Gas Plant in Service), account 101 (Gas Plant Leased to Others), account 102 (Gas Plant Held for Future Use) or account 110 (Other Plant) by distributing such amount over a fixed period or over the estimated remaining life of the plant.

59 Where it is anticipated by a company that plant will be abandoned owing to the exhaustion of a particular source of traffic, obsolescence or any other cause, the company shall not change from depreciation accounting to amortization accounting without first obtaining the authorization of the Board.

60(2) Amortization on assets included in account 110 (Other Plant) shall be debited to account 311 (Expense of Other Plant).

Note: The Board may have anticipated that negative salvage costs could be incurred on decommissioning and retirements but visualized those costs being recovered through self-insurance. For example, under section 61 Insurance the following subsections are pertinent

61(5) Where a company elects to create and maintain reserves for self-insurance, account 723 (Insurance) shall be debited with estimated amounts in lieu of commercial insurance premiums and account 290 (Insurance Appropriations) shall be credited with the estimated amounts.

61(6) A Schedule of risks covered by self-insurance shall be kept showing the character of risk and the rates used to compute the estimated amounts referred to in subsection (5).

61(7) The rates referred in subsection (6) shall not exceed commercial rates for the same protection.

61(9) Where the self-insurance schedule referred to in subsection (6) covers the retirement of plant, the accounting for the retirement shall be as outlined in section 36 and the self-insurance applicable to the retired item shall be transferred from account 290 (Insurance Appropriations) to account 105 (Accumulated Depreciation - Gas Plant) or account 106 (Accumulated Amortization - Gas Plant), as applicable.

Deferred Debit

171 Extraordinary Plant Losses

(1) This account shall include material losses authorized by the Board to be transferred from accumulated depreciation or accumulated amortization accounts to this account, in accordance with subsection 40(3).

(2) Before an amount is transferred to this account, a company shall provide the Board with full details of the calculation thereof together with the future accounting treatment proposed by the Company.

(3) Amounts recorded in this account shall be amortized by systematic debits to account 304 (Amortization), or otherwise disposed of as the Board may approve or direct.

The foregoing have been selected from U.A.R. - Gas Pipelines. Similar provisions are contained in the U.A.R. - Oil Pipelines.

Appendix VI

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